Statement of Basis

Prevention of Significant Deterioration Permit

Hyperion Energy Center

Near Elk Point

Union County, South Dakota

South Dakota Department of Environment and Natural Resources

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1.0 Background

On December 20, 2007, RTP Environmental Associates Inc., on behalf of Hyperion Refining LLC, submitted a Prevention Significant Deterioration preconstruction permit application to construct and operate a petroleum refinery, an integrated gasification combined cycle (IGCC) power plant, and ancillary equipment. Hyperion Refining and/or the Hyperion Energy Center project will be referred to as "Hyperion" in this document.

On February 20, 2008, the Department of Environment and Natural Resources (DENR) considered the application complete. Even though DENR considered the application complete, DENR requested additional information to clarify and verify terms in the application. In addition to stating the application was complete, DENR requested the following information:

1. The emission rates or percent reductions for the alternative options not proposed in the Best Available Control Technology (BACT) analysis;
2. The equipment sheet forms and/or process rates for specified equipment; and
3. The electronic spreadsheets used in the cost analysis for the BACT review.

2.0 Operational Description

The petroleum refinery will process up to 400,000 barrels per day of crude oil and 26,000 barrels per day of butane. The refinery will be capable of producing up to 255,000 barrels per day of ultra low sulfur gasoline, 169,000 barrels per day of ultra low diesel fuel, 40,000 barrels per day of jet fuel, 21,000 barrels per day of liquefied petroleum gas and other products such as sulfur and petroleum coke.

The integrated gasification combined cycle power plant will supply the refinery with hydrogen, electric power, and steam for its operation. The power plant is designed to provide the refinery with up to 450 million cubic feet per day of hydrogen, 200 megawatts worth of electricity, and 2.4 million pounds of steam per hour.

2.1 General Process Description of the Refinery

The petroleum refinery will use three major processes to produce its final products: 1) distillation; 2) conversion; and 3) purification.

The distillation process is the first step and is designed to separate the different components (e.g. naphtha, kerosene, and diesel) of the crude oil. Each component has a different boiling temperature where the component will turn from a liquid to a gas or from a gas to a liquid. By using this physical characteristic and varying the temperature, those components may be separated.

The conversion process is the second step and is designed to convert the leftover material called residuum from the distillation systems into more valuable products (e.g. gasoline and diesel fuel). This step uses chemical processes called hydrocracking or coking to produce those products.

The purification process is the last step and is designed to remove the impurities left in the product streams from both the distillation and conversion processes. The impurities are required to be removed so that the final products burn cleaner. This step uses a chemical process called hydrotreating to produce the refined products.

2.2 General Process Description of the Power Plant

The IGCC power plant will use two major processes to produce the hydrogen, electricity and steam: 1) gasification block; and 2) power/steam block.

The gasification block converts a solid fuel such as the petroleum coke or coal to a gas. This gas is generally referred to as synthetic gas or syngas. The syngas is composed of carbon monoxide, hydrogen, and impurities. The gasification process will also remove impurities before the syngas is burned in the power/steam block and will produce pure hydrogen, also called Pressure Swing Adsorption (PSA) tail gas, for the refinery process.

In the application, Hyperion proposed two fuel options for the power/steam block because the refinery will not produce enough petroleum coke to fire the power/steam block. In both options, diesel fuel will be used during startup. Under the first option, Hyperion will purchase additional petroleum coke or subbituminous coal to process through the gasification block and the main fuel for the power/steam block will be syngas or PSA tail gas. Under the second option, Hyperion will purchase natural gas and the main fuel for the power/steam block will be PSA tail gas and natural gas. In both options, the power/steam block would produce electricity and steam in a combined cycle system.

2.3 Process Equipment

Table 2-1 lists the units, controls, and processes identified in the permit application that need to be permitted for Hyperion.

Table 2-1 – Process Equipment

Unit	Description	Operating Rate [1]	Control Device
#1	Atmospheric crude charge heater #1. The unit is fired on refinery fuel gas and equipped with Low-NOx burners.	530 million Btus per hour heat input	Selective catalytic reduction
#2	Atmospheric crude charge heater #2. The unit is fired on refinery fuel gas and equipped with Low-NOx burners.	530 million Btus per hour heat input	Selective catalytic reduction
#3	Vacuum charge heater #1. The unit is fired on refinery fuel gas and equipped with Low-NOx burners.	215 million Btus per hour heat input	Selective catalytic reduction

Unit	Description	Operating Rate [1]	Control Device
#4	Vacuum charge heater #2. The unit is fired on refinery fuel gas and equipped with Low-NOx burners.	215 million Btus per hour heat input	Selective catalytic reduction
#5	Naphtha hydrotreater charge heater. The unit is fired on refinery fuel gas and equipped with Low-NOx burners.	200 million Btus per hour heat input	Selective catalytic reduction
#6	Naphtha hydrotreater stripper reboiler heater. The unit is fired on refinery fuel gas and equipped with Low-NOx burners.	169 million Btus per hour heat input	Selective catalytic reduction
#7	Naphtha splitter reboiler heater. The unit is fired on refinery fuel gas and equipped with Low-NOx burners.	247 million Btus per hour heat input	Selective catalytic reduction
#8	Distillate hydrotreater feed heater. The unit is fired on refinery fuel gas and equipped with Low-NOx burners.	141 million Btus per hour heat input	Selective catalytic reduction
#9	Delayed coker #1A heater. The unit is fired on refinery fuel gas and equipped with Low-NOx burners.	243 million Btus per hour heat input	Selective catalytic reduction
#10	Delayed coker #1B heater. The unit is fired on refinery fuel gas and equipped with Low-NOx burners.	243 million Btus per hour heat input	Selective catalytic reduction
#11	Delayed coker #2A heater. The unit is fired on refinery fuel gas and equipped with Low-NOx burners.	243 million Btus per hour heat input	Selective catalytic reduction
#12	Delayed coker #2B heater. The unit is fired on refinery fuel gas and equipped with Low-NOx burners.	243 million Btus per hour heat input	Selective catalytic reduction
#13	Number one platformer charge and interheater #1. The unit is fired on refinery fuel gas and equipped with Low-NOx burners.	825 million Btus per hour heat input	Selective catalytic reduction
#14	Number one platformer interheater #2 and #3. The unit is fired on refinery fuel gas and equipped with Low-NOx burners.	493 million Btus per hour heat input	Selective catalytic reduction
#15	Number two platformer charge and interheater #1. The unit is fired on refinery fuel gas and equipped with Low-NOx burners.	825 million Btus per hour heat input	Selective catalytic reduction
#16	Number two platformer interheater #2 and #3. The unit is fired on refinery fuel gas and equipped with Low-NOx burners.	493 million Btus per hour heat input	Selective catalytic reduction
#17	Oleflex heater. The unit is fired on refinery fuel gas and equipped with Low-NOx burners.	604 million Btus per hour heat input	Selective catalytic reduction

Unit	Description	Operating Rate [1]	Control Device
#18	Reformate splitter reboiler. The unit is fired on refinery fuel gas and equipped with Low-NOx burners.	138 million Btus per hour heat input	Selective catalytic reduction
#19	Number one hydrocracker fractionator feed heater. The unit is fired on refinery fuel gas and equipped with Low-NOx burners.	676 million Btus per hour heat input	Selective catalytic reduction
#20	Number two hydrocracker fractionator feed heater. The unit is fired on refinery fuel gas and equipped with Low-NOx burners.	676 million Btus per hour heat input	Selective catalytic reduction
#21	Number one hydrocracker heater #1A. The unit is fired on refinery fuel gas and equipped with Ultra Low- NOx burners.	67 million Btus per hour heat input	Not applicable
#22	Number one hydrocracker heater #1B. The unit is fired on refinery fuel gas and equipped with Ultra Low- NOx burners.	67 million Btus per hour heat input	Not applicable
#23	Number one hydrocracker heater #1C. The unit is fired on refinery fuel gas and equipped with Ultra Low- NOx burners.	67 million Btus per hour heat input	Not applicable
#24	Number one hydrocracker heater #2A. The unit is fired on refinery fuel gas and equipped with Ultra Low- NOx burners.	65 million Btus per hour heat input	Not applicable
#25	Number one hydrocracker heater #2B. The unit is fired on refinery fuel gas and equipped with Ultra Low- NOx burners.	65 million Btus per hour heat input	Not applicable
#26	Number two hydrocracker heater #1A. The unit is fired on refinery fuel gas and equipped with Ultra Low- NOx burners.	67 million Btus per hour heat input	Not applicable
#27	Number two hydrocracker heater #1B. The unit is fired on refinery fuel gas and equipped with Ultra Low- NOx burners.	67 million Btus per hour heat input	Not applicable
#28	Number two hydrocracker heater #1C. The unit is fired on refinery fuel gas and equipped with Ultra Low- NOx burners.	67 million Btus per hour heat input	Not applicable
#29	Number two hydrocracker heater #2A. The unit is fired on refinery fuel gas and equipped with Ultra Low- NOx burners.	65 million Btus per hour heat input	Not applicable
#30	Number two hydrocracker heater #2B. The unit is fired on refinery fuel gas and equipped with Ultra Low- NOx burners.	65 million Btus per hour heat input	Not applicable
#31	Number one platformer catalyst regenerator.	79,500 barrels per day	Caustic scrubber
#32	Number two platformer catalyst regenerator.	79,500 barrels per day	Caustic scrubber
#33	Oleflex catalyst regenerator.	18,000 barrels per day	Caustic scrubber

Unit	Description	Operating Rate [1]	Control Device
#34a	Coke drum #1 – Steam vent A.	60,000 barrels per day	Not applicable
#34b	Coke drum #1 – Steam vent B.		Not applicable
#34c	Coke drum #1 – Steam vent C.		Not applicable
#34d	Coke drum #1 – Steam vent D.		Not applicable
#35a	Coke drum #2 – Steam vent A.	60,000 barrels per day	Not applicable
#35b	Coke drum #2 – Steam vent B.		Not applicable
#35c	Coke drum #2 – Steam vent C.		Not applicable
#35d	Coke drum #2 – Steam vent D.		Not applicable
#36	Refinery flare #1. The unit is fired on natural gas and the exhaust gases from the refinery during emergency conditions.	1 million Btus per hour heat input [2]	Not applicable
#37	Refinery flare #2. The unit is fired on natural gas and the exhaust gases from the refinery during emergency conditions.	1 million Btus per hour heat input [2]	Not applicable
#38	Refinery flare #3. The unit is fired on natural gas and the exhaust gases from the refinery during emergency conditions.	1 million Btus per hour heat input [2]	Not applicable
#39	Refinery flare #4. The unit is fired on natural gas and the exhaust gases from the refinery during emergency conditions.	1 million Btus per hour heat input [2]	Not applicable
#40	Refinery flare #5. The unit is fired on natural gas and the exhaust gases from the refinery during emergency conditions.	1 million Btus per hour heat input [2]	Not applicable
#41	Fan air cooler and wet cooling tower. The unit has 13 cells.	130,000 gallons per minute	High efficiency drift eliminators
	Sulfur recover plant. The sulfur recovery plant consists of six lines; each includes a Claus Reactor and tail gas treater.	2,040 long tons per day (Option #1) and 1,884 long tons per day (Option #2) [3]	Six thermal oxidizers
#42a	Thermal oxidizer #1. The thermal oxidizer is fired on refinery fuel gas and natural gas and equipped with Low-NOx burners.	101 million Btus per hour heat input	
#42b	Thermal oxidizer #2. The thermal oxidizer is fired on refinery fuel gas and natural gas and equipped with Low-NOx burners.	101 million Btus per hour heat input	
#42c	Thermal oxidizer #3. The thermal oxidizer is fired on refinery fuel gas and natural gas and equipped with Low-NOx burners.	101 million Btus per hour heat input	
#42d	Thermal oxidizer #4. The thermal oxidizer is fired on refinery fuel gas and natural gas and equipped with Low-NOx burners.	101 million Btus per hour heat input	

Unit	Description	Operating Rate [1]	Control Device
#42e	Thermal oxidizer #5. The thermal oxidizer is fired on refinery fuel gas and natural gas and equipped with Low-NOx burners.	101 million Btus per hour heat input	
#42f	Thermal oxidizer #6. The thermal oxidizer is fired on refinery fuel gas and natural gas and equipped with Low-NOx burners.	101 million Btus per hour heat input	
#43	Railcar loading rack.	16,000 barrels per day	Vacuum-regenerated, carbon adsorption-based vapor recovery system
#44	Truck loading rack.	16,000 barrels per day	Vacuum-regenerated, carbon adsorption-based vapor recovery system
#45a	Wastewater treatment plant. The wastewater treatment plant will consist of a wastewater stripper and equipped with closed vents on the oil/water separators and primary dissolved air flotation systems.	Not available	Catalytic oxidizer and selective catalytic reduction
	Catalytic oxidizer. The catalytic oxidizer is fired on refinery fuel gas and natural gas.	1 million Btus per hour heat input	
#45b	Wastewater treatment drains with a vent.	Not applicable	Closed vent system and dual carbon canisters
#45c	Two aeration tanks.	Not applicable	Internal floating roof
	Petroleum coke storage building.	1,000 tons per hour	Four baghouses
#46a	Baghouse #1.		
#46b	Baghouse #2.		
#46c	Baghouse #3.		
#46d	Baghouse #4.		
#47	Coal/Coke unloading building.	1,000 tons per hour	Baghouse
#48	Flux unloading building.	100 tons per hour	Baghouse
#49	Slag loading building.	100 tons per hour	Baghouse
#50	Gasification system. Oxygen blown, slagging gasifiers with shift conversion reactors.	10,564 million Btus per hour heat input	Flare
	Flare. The unit is fired on natural gas and the exhaust gases from the startup, shutdown and malfunctions of the gasification system,	787 million Btus per hour heat input	
#51	Gasifier startup burner #1. The unit is fired on natural gas and equipped with Low-NOx burners.	18 million Btus per hour heat input	Not applicable

Unit	Description	Operating Rate [1]	Control Device
#52	Gasifier startup burner #2. The unit is fired on natural gas and equipped with Low-NOx burners.	18 million Btus per hour heat input	Not applicable
#53	Gasifier startup burner #3. The unit is fired on natural gas and equipped with Low-NOx burners.	18 million Btus per hour heat input	Not applicable
#54	Gasifier startup burner #4. The unit is fired on natural gas and equipped with Low-NOx burners.	18 million Btus per hour heat input	Not applicable
#55	Gasifier startup burner #5. The unit is fired on natural gas and equipped with Low-NOx burners.	18 million Btus per hour heat input	Not applicable
#56	Gasifier startup burner #6. The unit is fired on natural gas and equipped with Low-NOx burners.	18 million Btus per hour heat input	Not applicable
#57	Gasifier startup burner #7. The unit is fired on natural gas and equipped with Low-NOx burners.	18 million Btus per hour heat input	Not applicable
#58	Gasifier startup burner #8. The unit is fired on natural gas and equipped with Low-NOx burners.	18 million Btus per hour heat input	Not applicable
#59	Power island acid gas removal system. Rectisol ® wash	544 million standard cubic feet of syngas per day	Not applicable
#60	Combined cycle gas turbine #1.	1,677 million Btus per hour heat input	
	Option #1 – The unit is fired on syngas, pressure swing adsorption tail gas, and ultra low sulfur distillate oil and equipped with Low-NOx duct burners and diluent injection.		Catalytic reactor system and selective catalytic reduction
	Option #2 – The unit is fired on pressure swing adsorption tail gas, natural gas, and ultra low sulfur distillate oil and equipped with Low-NOx duct burners and dry Low-NOx combustion burners.		
#61	Combined cycle gas turbine #2.	1,677 million Btus per hour heat input	
	Option #1 – The unit is fired on syngas, pressure swing adsorption tail gas, and ultra low sulfur distillate oil and equipped with Low-NOx duct burners and diluent injection.		Catalytic reactor system and selective catalytic reduction
	Option #2 – The unit is fired on pressure swing adsorption tail gas, natural gas, and ultra low sulfur distillate oil and equipped with Low-NOx duct burners and dry Low-NOx combustion burners.		

Unit	Description	Operating Rate [1]	Control Device
#62	Combined cycle gas turbine #3. Option #1 – The unit is fired on syngas, pressure swing adsorption tail gas, and ultra low sulfur distillate oil and equipped with Low-NOx duct burners and diluent injection. Option #2 – The unit is fired on pressure swing adsorption tail gas, natural gas, and ultra low sulfur distillate oil and equipped with Low-NOx duct burners and dry Low-NOx combustion burners.	1,677 million Btus per hour heat input	Catalytic reactor system and selective catalytic reduction
#63	Combined cycle gas turbine #4. Option #1 – The unit is fired on syngas, pressure swing adsorption tail gas, and ultra low sulfur distillate oil and equipped with Low-NOx duct burners and diluent injection. Option #2 – The unit is fired on pressure swing adsorption tail gas, natural gas, and ultra low sulfur distillate oil and equipped with Low-NOx duct burners and dry Low-NOx combustion burners.	1,677 million Btus per hour heat input	Catalytic reactor system and selective catalytic reduction Catalytic reactor system and selective catalytic reduction
#64	Combined cycle gas turbine #5. Option #1 – The unit is fired on syngas, pressure swing adsorption tail gas, and ultra low sulfur distillate oil and equipped with Low-NOx duct burners and diluent injection. Option #2 – The unit is fired on pressure swing adsorption tail gas, natural gas, and ultra low sulfur distillate oil and equipped with Low-NOx duct burners and dry Low-NOx combustion burners.	1,677 million Btus per hour heat input	Catalytic reactor system and selective catalytic reduction
#65	Emergency generator #1. The unit is fired on ultra low sulfur distillate oil.	600 kilowatts	Not applicable
#66	Emergency generator #2. The unit is fired on ultra low sulfur distillate oil.	600 kilowatts	Not applicable
#67	Emergency generator #3. The unit is fired on ultra low sulfur distillate oil.	600 kilowatts	Not applicable
#68	Emergency generator #4. The unit is fired on ultra low sulfur distillate oil.	600 kilowatts	Not applicable
#69	Fire water pump #1. The unit is fired on ultra low sulfur distillate oil.	2,250 kilowatts	Not applicable
#70	Fire water pump #2. The unit is fired on ultra low sulfur distillate oil.	2,250 kilowatts	Not applicable

Unit	Description	Operating Rate [1]	Control Device
#71	Aboveground storage tank #RF1-1. The tank will store crude oil or other petroleum liquids.	21,000,000 gallons	Internal floating roof
#72	Aboveground storage tank #RF1-2. The tank will store crude oil or other petroleum liquids.	21,000,000 gallons	Internal floating roof
#73	Aboveground storage tank #RF1-3. The tank will store crude oil or other petroleum liquids.	21,000,000 gallons	Internal floating roof
#74	Aboveground storage tank #RF1-4. The tank will store crude oil or other petroleum liquids.	21,000,000 gallons	Internal floating roof
#75	Aboveground storage tank #RF1-5. The tank will store crude oil or other petroleum liquids.	21,000,000 gallons	Internal floating roof
#76	Aboveground storage tank #RF1-6. The tank will store crude oil or other petroleum liquids.	21,000,000 gallons	Internal floating roof
#77	Aboveground storage tank #RF1-7. The tank will store crude oil or other petroleum liquids.	21,000,000 gallons	Internal floating roof
#78	Aboveground storage tank #RF1-8. The tank will store crude oil or other petroleum liquids.	21,000,000 gallons	Internal floating roof
#79	Aboveground storage tank #RF1-9. The tank will store crude oil or other petroleum liquids.	21,000,000 gallons	Internal floating roof
#80	Aboveground storage tank #RF1-10. The tank will store crude oil or other petroleum liquids.	21,000,000 gallons	Internal floating roof
#81	Aboveground storage tank #RP4-1. The tank will store conventional regular gasoline or other petroleum liquids.	8,400,000 gallons	Internal floating roof
#82	Aboveground storage tank #RP4-2. The tank will store conventional regular gasoline or other petroleum liquids.	8,400,000 gallons	Internal floating roof
#83	Aboveground storage tank #RP5-1. The tank will store conventional premium gasoline or other petroleum liquids.	8,400,000 gallons	Internal floating roof
#84	Aboveground storage tank #RP6-1. The tank will store conventional regular subgrade gasoline or other petroleum liquids.	8,400,000 gallons	Internal floating roof

Unit	Description	Operating Rate [1]	Control Device
#85	Aboveground storage tank #RP6-2. The tank will store conventional regular subgrade gasoline or other petroleum liquids.	8,400,000 gallons	Internal floating roof
#86	Aboveground storage tank #RP6-3. The tank will store conventional regular subgrade gasoline or other petroleum liquids.	8,400,000 gallons	Internal floating roof
#87	Aboveground storage tank #RP6-4. The tank will store conventional regular subgrade gasoline or other petroleum liquids.	8,400,000 gallons	Internal floating roof
#88	Aboveground storage tank #RP6-5. The tank will store conventional regular subgrade gasoline or other petroleum liquids.	8,400,000 gallons	Internal floating roof
#89	Aboveground storage tank #RP6-6. The tank will store conventional regular subgrade gasoline or other petroleum liquids.	8,400,000 gallons	Internal floating roof
#90	Aboveground storage tank #RP6-7. The tank will store conventional regular subgrade gasoline or other petroleum liquids.	8,400,000 gallons	Internal floating roof
#91	Aboveground storage tank #RP7-1. The tank will store conventional premium subgrade gasoline or other petroleum liquids.	8,400,000 gallons	Internal floating roof
#92	Aboveground storage tank #RP8-1. The tank will store reformulated regular gasoline blendstock for oxygen blending or other petroleum liquids.	8,400,000 gallons	Internal floating roof
#93	Aboveground storage tank #RP8-2. The tank will store reformulated regular gasoline blendstock for oxygen blending or other petroleum liquids.	8,400,000 gallons	Internal floating roof
#94	Aboveground storage tank #RP8-3. The tank will store reformulated regular gasoline blendstock for oxygen blending or other petroleum liquids.	8,400,000 gallons	Internal floating roof
#95	Aboveground storage tank #RP8-4. The tank will store reformulated regular gasoline blendstock for oxygen blending or other petroleum liquids.	8,400,000 gallons	Internal floating roof
#96	Aboveground storage tank #RP9-1. The tank will store reformulated premium gasoline blendstock for oxygen blending or other petroleum liquids.	8,400,000 gallons	Internal floating roof
#97	Aboveground storage tank #RP10-1. The tank will store jet fuel or other petroleum liquids.	8,400,000 gallons	Internal floating roof

Unit	Description	Operating Rate [1]	Control Device
#98	Aboveground storage tank #RP10-2. The tank will store jet fuel or other petroleum liquids.	8,400,000 gallons	Internal floating roof
#99	Aboveground storage tank #RP10-3. The tank will store jet fuel or other petroleum liquids.	8,400,000 gallons	Internal floating roof
#100	Aboveground storage tank #RP11-1. The tank will store ultra low sulfur diesel fuel or other petroleum liquids.	8,400,000 gallons	Internal floating roof
#101	Aboveground storage tank #RP11-2. The tank will store ultra low sulfur diesel fuel or other petroleum liquids.	8,400,000 gallons	Internal floating roof
#102	Aboveground storage tank #RP11-3. The tank will store ultra low sulfur diesel fuel or other petroleum liquids.	8,400,000 gallons	Internal floating roof
#103	Aboveground storage tank #RP11-4. The tank will store ultra low sulfur diesel fuel or other petroleum liquids.	8,400,000 gallons	Internal floating roof
#104	Aboveground storage tank #RP11-5. The tank will store ultra low sulfur diesel fuel or other petroleum liquids.	8,400,000 gallons	Internal floating roof
#105	Aboveground storage tank #RP11-6. The tank will store ultra low sulfur diesel fuel or other petroleum liquids.	8,400,000 gallons	Internal floating roof
#106	Aboveground storage tank #RP11-7. The tank will store ultra low sulfur diesel fuel or other petroleum liquids.	8,400,000 gallons	Internal floating roof
#107	Aboveground storage tank #RP11-8. The tank will store ultra low sulfur diesel fuel or other petroleum liquids.	8,400,000 gallons	Internal floating roof
#108	Aboveground storage tank #RP11-9. The tank will store ultra low sulfur diesel fuel or other petroleum liquids.	8,400,000 gallons	Internal floating roof
#109	Aboveground storage tank #RP11-10. The tank will store ultra low sulfur diesel fuel or other petroleum liquids.	8,400,000 gallons	Internal floating roof
#110	Aboveground storage tank #RP11-11. The tank will store ultra low sulfur diesel fuel or other petroleum liquids.	8,400,000 gallons	Internal floating roof
#111	Aboveground storage tank #IP3-1. The tank will store light straight run from the crude unit or other petroleum liquids.	10,500,000 gallons	Internal floating roof

Unit	Description	Operating Rate [1]	Control Device
#112	Aboveground storage tank #IP3-2. The tank will store light straight run from the crude unit or other petroleum liquids.	10,500,000 gallons	Internal floating roof
#113	Aboveground storage tank #IP4-1. The tank will store coker naphtha or other petroleum liquids.	8,400,000 gallons	Internal floating roof
#114	Aboveground storage tank #IP5-1. The tank will store hydrotreated light naphtha or other petroleum liquids.	6,300,000 gallons	Internal floating roof
#115	Aboveground storage tank #IP5-2. The tank will store hydrotreated light naphtha or other petroleum liquids.	6,300,000 gallons	Internal floating roof
#116	Aboveground storage tank #IP6-1. The tank will store hydrotreated heavy naphtha or other petroleum liquids.	8,400,000 gallons	Internal floating roof
#117	Aboveground storage tank #IP6-2. The tank will store hydrotreated heavy naphtha or other petroleum liquids.	8,400,000 gallons	Internal floating roof
#118	Aboveground storage tank #IP7-1. The tank will store heavy hydrocracker naphtha or other petroleum liquids.	14,000,000 gallons	Internal floating roof
#119	Aboveground storage tank #IP7-2. The tank will store heavy hydrocracker naphtha or other petroleum liquids.	14,000,000 gallons	Internal floating roof
#120	Aboveground storage tank #IP8-1. The tank will store light hydrocracker naphtha or other petroleum liquids.	6,300,000 gallons	Internal floating roof
#121	Aboveground storage tank #IP8-2. The tank will store light hydrocracker naphtha or other petroleum liquids.	6,300,000 gallons	Internal floating roof
#122	Aboveground storage tank #IP9-1. The tank will store light reformate or other petroleum liquids.	4,200,000 gallons	Internal floating roof
#123	Aboveground storage tank #IP10-1. The tank will store saturated light hydrocracker naphtha or other petroleum liquids.	2,100,000 gallons	Internal floating roof
#124	Aboveground storage tank #IP10-2. The tank will store saturated light hydrocracker naphtha or other petroleum liquids.	2,100,000 gallons	Internal floating roof
#125	Aboveground storage tank #IP11-1. The tank will store reformate or other petroleum liquids.	8,400,000 gallons	Internal floating roof

Unit	Description	Operating Rate [1]	Control Device
#126	Aboveground storage tank #IP11-2. The tank will store reformate or other petroleum liquids.	8,400,000 gallons	Internal floating roof
#127	Aboveground storage tank #IP11-3. The tank will store reformate or other petroleum liquids.	8,400,000 gallons	Internal floating roof
#128	Aboveground storage tank #IP11-4. The tank will store reformate or other petroleum liquids.	8,400,000 gallons	Internal floating roof
#129	Aboveground storage tank #IP12-1. The tank will store heavy reformate or other petroleum liquids.	8,400,000 gallons	Internal floating roof
#130	Aboveground storage tank #IP13-1. The tank will store isomerate or other petroleum liquids.	6,300,000 gallons	Internal floating roof
#131	Aboveground storage tank #IP13-2. The tank will store isomerate or other petroleum liquids.	6,300,000 gallons	Internal floating roof
#132	Aboveground storage tank #IP14-1. The tank will store indirect alkylation process alkylate or other petroleum liquids.	2,500,000 gallons	Internal floating roof
#133	Aboveground storage tank #IP14-2. The tank will store indirect alkylation process alkylate or other petroleum liquids.	2,500,000 gallons	Internal floating roof
#134	Aboveground storage tank #IP15-1. The tank will store indirect alkylation process C12+ stream or other petroleum liquids.	450,000 gallons	Internal floating roof
#135	Aboveground storage tank #IP16-1. The tank will store straight run kerosene or other petroleum liquids.	4,200,000 gallons	Internal floating roof
#136	Aboveground storage tank #IP16-2. The tank will store straight run kerosene or other petroleum liquids.	4,200,000 gallons	Internal floating roof
#137	Aboveground storage tank #IP17-1. The tank will store straight run diesel or other petroleum liquids.	4,200,000 gallons	Internal floating roof
#138	Aboveground storage tank #IP17-2. The tank will store straight run diesel or other petroleum liquids.	4,200,000 gallons	Internal floating roof
#139	Aboveground storage tank #IP17-3. The tank will store straight run diesel or other petroleum liquids.	4,200,000 gallons	Internal floating roof

Unit	Description	Operating Rate [1]	Control Device
#140	Aboveground storage tank #IP18-1. The tank will store atmospheric gas oil or other petroleum liquids.	4,200,000 gallons	Fixed roof
#141	Aboveground storage tank #IP19-1. The tank will store light coker gas oil or other petroleum liquids.	4,200,000 gallons	Internal floating roof
#142	Aboveground storage tank #IP19-2. The tank will store light coker gas oil or other petroleum liquids.	4,200,000 gallons	Internal floating roof
#143	Aboveground storage tank #IP20-1. The tank will store distillate hydrotreater desulfurization ultra low sulfur diesel fuel or other petroleum liquids.	8,400,000 gallons	Internal floating roof
#144	Aboveground storage tank #IP20-2. The tank will store distillate hydrotreater desulfurization ultra low sulfur diesel fuel or other petroleum liquids.	8,400,000 gallons	Internal floating roof
#145	Aboveground storage tank #IP20-3. The tank will store distillate hydrotreater desulfurization ultra low sulfur diesel fuel or other petroleum liquids.	8,400,000 gallons	Internal floating roof
#146	Aboveground storage tank #IP21-1. The tank will store distillate hydrotreater desulfurization Naphtha or other petroleum liquids.	2,100,000 gallons	Internal floating roof
#147	Aboveground storage tank #IP22-1. The tank will store hydrocracker diesel or other petroleum liquids.	8,400,000 gallons	Internal floating roof
#148	Aboveground storage tank #IP22-2. The tank will store hydrocracker diesel or other petroleum liquids.	8,400,000 gallons	Internal floating roof
#149	Aboveground storage tank #IP23-1. The tank will store vacuum gas oil or other petroleum liquids.	14,000,000 gallons	Fixed roof
#150	Aboveground storage tank #IP23-2. The tank will store vacuum gas oil or other petroleum liquids.	14,000,000 gallons	Fixed roof
#151	Aboveground storage tank #IP23-3. The tank will store vacuum gas oil or other petroleum liquids.	14,000,000 gallons	Fixed roof
#152	Aboveground storage tank #IP24-1. The tank will store heavy coker gas oil or other petroleum liquids.	4,200,000 gallons	Fixed roof

Unit	Description	Operating Rate [1]	Control Device
#153	Aboveground storage tank #IP24-2. The tank will store heavy coker gas oil or other petroleum liquids.	4,200,000 gallons	Fixed roof
#154	Aboveground storage tank #IP25-1. The tank will store vacuum residuum or other petroleum liquids.	21,000,000 gallons	Fixed roof
#155	Aboveground storage tank #IP25-2. The tank will store vacuum residuum or other petroleum liquids.	21,000,000 gallons	Fixed roof
#156	Aboveground storage tank #IP26-1. The tank will store ethanol or other petroleum liquids.	150,000 gallons	Internal floating roof
#157	Aboveground storage tank #IP26-2. The tank will store ethanol or other petroleum liquids.	150,000 gallons	Internal floating roof
#158	Aboveground storage tank #SS1-1. The tank will store slop or other petroleum liquids.	3,400,000 gallons	Internal floating roof
#159	Aboveground storage tank #SS1-2. The tank will store slop or other petroleum liquids.	3,400,000 gallons	Internal floating roof
#160	Aboveground storage tank #SS2-1. The tank will store coker, crude, and/or vacuum sour water or other petroleum liquids.	6,300,000 gallons	Internal floating roof
#161	Aboveground storage tank #SS3-1. The tank will store hydrocracker and distillate hydrotreater desulfurization sour water or other petroleum liquids.	6,300,000 gallons	Internal floating roof
#162	Aboveground storage tank #SS4-1. The tank will store swing sour water or other petroleum liquids.	6,300,000 gallons	Internal floating roof
#163	Aboveground storage tank #SS8-1. The tank will store amine (lean) or other petroleum liquids.	6,300,000 gallons	Fixed roof
#164	Aboveground storage tank #SS9-1. The tank will store amine (rich) or other petroleum liquids.	6,300,000 gallons	Internal floating roof
#165	Aboveground storage tank #SS10-1. The tank will store swing sour or sweet amine or other petroleum liquids.	6,300,000 gallons	Internal floating roof
#166	Aboveground storage tank #SS14-1. The tank will store gasoline with additives or other petroleum liquids.	150,000 gallons	Internal floating roof
#167	Aboveground storage tank #SS15-1. The tank will store gasoline with additives or other petroleum liquids.	150,000 gallons	Internal floating roof

Unit	Description	Operating Rate [1]	Control Device
#168	Aboveground storage tank #SS16-1. The tank will store gasoline with additives or other petroleum liquids.	150,000 gallons	Internal floating roof
#169	Aboveground storage tank #SS17-1. The tank will store gasoline with additives or other petroleum liquids.	150,000 gallons	Internal floating roof
#170	Aboveground storage tank #SS18-1. The tank will store gasoline with additives or other petroleum liquids.	150,000 gallons	Internal floating roof
#171	Aboveground storage tank #SS19-1. The tank will store gasoline with additives or other petroleum liquids.	150,000 gallons	Internal floating roof
#172	Aboveground storage tank #SS20-1. The tank will store kerosene with additives or other petroleum liquids.	150,000 gallons	Internal floating roof
#173	Aboveground storage tank #SS21-1. The tank will store diesel with additives or other petroleum liquids.	140,000 gallons	Internal floating roof
#174	Aboveground storage tank #SS22-1. The tank will store methanol or other petroleum liquids.	31,000 gallons	Internal floating roof

[1] – The operating rate is the nominal or manufacturer listed operating rate noted in the PSD application and are descriptive only;
[2] – Represents maximum design operating rate of the pilot gas flow rate; and
[3] – The amount of sulfur produced per day is based on which fuel Option for the combined cycle combustion turbines. Option #1 consists of firing the combined cycle gas turbines with syngas, pressure swing adsorption tail gas; and distillate oil. Option #2 consists of firing the combined cycle gas turbines with pressure swing adsorption tail gas, natural gas, and distillate oil.

3.0 New Source Performance Standards

DENR reviewed the New Source Performance Standards (NSPS) under 40 CFR Part 60 and determined that the following may be applicable to Hyperion.

3.1 ARSD 74:36:07:01 – Subpart A

The General Provisions in 40 CFR Part 60, Subpart A require general requirements for notifications, monitoring, performance testing, reporting, recordkeeping, and operation and maintenance. If Hyperion is applicable to a NSPS, the project is applicable to this subpart. As noted in the following reviews, Hyperion is applicable to NSPS standards and is therefore, applicable to this subpart.

3.2 ARSD 74:36:07:03 – Subpart Da

On August 20, 2007, RTP Environmental Associates requested concurrence from Enviornmental Protection Agency (EPA) Headquarters that this subpart applies to Hyperion. On September 24, 2007, EPA Headquarters responded to RTP Environmental Associates that this request should be directed through South Dakota's DENR.

The Standards of Performance for Electric Utility Steam Generating Units for which construction is commenced after September 18, 1978, are applicable to the following electric utility steam generators:

1. The electric utility steam generating unit that has a heat input greater than 250 million Btus per hour; and
2. The electric utility steam generating unit commences construction, modification, or reconstruction after September 18, 1978.

An electric utility steam generating unit is defined as any steam electric generating unit that is constructed for the purpose of supplying more than one-third of its potential electric output capacity and more than 25 megawatts net-electrical output to any utility power distribution system for sale.

As noted in the February 9, 2007, federal register notice, EPA revised this subpart to clarify that IGCC facilities are subject to this subpart. This subpart is applicable to the following combined cycle gas turbines that are not an electric utility steam generating unit:

1. The combined cycle gas turbine has a heat input greater than 250 million Btus per hour;
2. The combined cycle gas turbine is intended to burn more than 50% of its fuel from solid-derived fuel; and
3. The combined cycle gas turbine commences construction, modification, or reconstruction after February 28, 2005.

Hyperion proposes to construct and operate five combined cycle gas turbines (Unit #60 through #64). Hyperion will not supply any of its electric output capacity to a utility power distribution system for sale. Therefore, the five combined cycle gas turbines are not considered an electrical utility steam generating unit.

Each combined cycle gas turbines will have a heat input of 1,677 million Btus per hour. As stated above, Hyperion proposed two options for fueling the combined cycle gas turbines. Option one identifies syngas and PSA tail gas produced from the gasification of petroleum coke or coal as the main fuel. Option two identifies natural gas and PSA tail gas produced from the gasification of petroleum coke or coal as the main fuel.

DENR agrees with Hyperion's interpretation that the combined cycle gas turbines are subject to this subpart because the units are fired with syngas and PSA tail gas as the main fuel source. DENR agrees because the revisions to this subpart did not require the combined cycle gas turbines to be associated with an electric utility steam generating unit as the title of the subpart suggests. Hyperion is subject to this subpart for the combined cycle gas turbines associated with the IGCC facility under option one, which is burning syngas and PSA tail gas. Hyperion may be subject to this subpart for the combined cycle gas turbines under option two, which is burning natural gas and PSA tail gas. The subpart is applicable if PSA tail gas provides 50 percent or more of the fuel source for the combined cycle combustion turbines.

The subpart contains opacity, particulate matter, sulfur dioxide, nitrogen oxide, and mercury emission limits. For combined cycle gas turbines that are not an electric utility steam generating unit, such as at Hyperion, the mercury limits in this subpart do not apply. In addition, on February 8, 2008, the United States Court of Appeals vacated the mercury emission limits in this subpart. The emission limits that are applicable to Hyperion are noted in Table 3-1.

Table 3-1 – 40 CFR Part 60, Subpart Da Air Emission Limits

Pollutant	Citation	NSPS Limit
Opacity	40 CFR §60.42Da(b)	20 percent opacity (6-minute average), except for one 6-minute period per hour of not more than 27 percent opacity.
Particulate matter	40 CFR §60.42Da(c)	0.14 pounds per megawatt-hour gross energy output or 0.015 pounds per million Btus heat input.
Sulfur dioxide	40 CFR §60.43Da(i)	1.4 pounds per megawatt-hour gross energy output or 5 percent of the potential combustion concentration (95 percent reduction). Compliance with the sulfur dioxide limit and percent reduction are based on a 30-day rolling average.
Nitrogen oxide	40 CFR §60.44Da(e)(1)	1.0 pounds per megawatt-hour gross energy output. Compliance with the nitrogen oxide limit is based on a 30-day rolling average.

Under 40 CFR §60.42Da(d), there is an alternative emission limit for particulate matter of 0.03 pounds per million Btu of heat input and 0.1 percent of the combustion concentration determined according to the procedure in 40 CFR §60.48Da(o)(5) (99.9 percent reduction). This alternative is not mentioned in the table because the most restrictive limit for particulate matter was identified in the table for comparison to the BACT limit that will be discussed later on in this review.

3.3 ARSD 74:36:07:04 – Subpart Db

On August 20, 2007, RTP Environmental Associates requested concurrence from EPA Headquarters that this subpart did not apply to Hyperion because Hyperion was applicable to 40 CFR Part 60, Subpart Da. On September 24, 2007, EPA Headquarters responded to RTP Environmental Associates that this request should be directed through South Dakota's DENR.

The Standards of Performance for Industrial, Commercial, and Institutional Steam Generating Units are applicable to the following steam generating units:

1. Each steam generating unit for which construction commenced after June 19, 1984; and
2. The steam generating unit has a maximum design heat input capacity equal to or greater than 100 million Btus per hour.

A steam generating unit is a device that combusts any fuel or byproduct/waste and produces steam or heats water or any other heat transfer medium. A process heater is an enclosed device using a controlled flame, that is not a boiler, and the unit's primary purpose is to transfer heat indirectly to a process material (liquid, gas, or solid) or to a heat transfer material for use in a process unit, instead of generating steam.

In accordance with 40 CFR §60.40b(e) and (i), this subpart exempts those steam generating units meeting the applicability requirements under 40 CFR Part 60, Subpart Da and those heat recovery steam generators associated with combined cycle gas turbines under 40 CFR Part 60, Subpart KKKK.

Hyperion proposes to construct and operate process heaters and combined cycle gas turbines. The process heaters are not considered steam generating units. The combined cycle gas turbines are subject to 40 CFR Part 60, Subpart Da or Subpart KKKK. Therefore, Hyperion is not subject to this subpart.

3.4 ARSD 74:36:07:05 – Subpart Dc

The Standards of Performance for Small Industrial, Commercial, and Institutional Steam Generating Units are applicable to the following steam generating units:

1. Each steam generating unit for which construction commenced after June 9, 1989; and
2. The steam generating unit has a maximum design heat input capacity equal to or greater than 10 million Btus per hour but less than 100 million Btus per hour.

A steam generating unit is a device that combusts any fuel or byproduct/waste and produces steam or heats water or any other heat transfer medium. A process heater is an enclosed device using a controlled flame, that is not a boiler, and the unit's primary purpose is to transfer heat indirectly to a process material (liquid, gas, or solid) or to a heat transfer material for use in a process unit, instead of generating steam.

Hyperion proposes to construct and operate process heaters and combined cycle gas turbines. The combined cycle gas turbines have a heat input greater than 100 million Btus per hour. The process heaters are not considered steam generating units. Therefore, Hyperion is not subject to this subpart.

3.5 ARSD 74:36:07:46 – Subpart J

On August 20, 2007, RTP Environmental Associates requested concurrence from EPA Headquarters that this subpart applies to the combustion turbines associated with the IGCC power plant for Hyperion because the IGCC power plant is considered part of the petroleum refinery. On September 24, 2007, EPA Headquarters responded to RTP Environmental Associates that this request should be directed through South Dakota's DENR.

The Standards of Performance for Petroleum Refineries are applicable to the following systems:

1. Each fluid catalytic cracking unit catalyst regenerators and fuel gas combustion devices for which construction or modification commenced after June 11, 1973; and/or
2. Each Claus sulfur recovery plant for which construction or modification commenced after October 4, 1976.

A fluid catalytic cracking unit catalyst regenerator means a refinery process unit in which hydrocarbons are fractured or react in a fluidized bed to form other hydrocarbons. A fuel gas combustion device means any equipment such as process heaters, boilers and flares used to combust fuel gas. Claus sulfur recovery plant means a process unit which recovers sulfur from hydrogen sulfide.

Hyperion proposes to construct several hydrocracker units. The hydrocracker units convert hydrocarbons by fracturing or reacting in fixed-bed catalytic reactors where the processes occur under high pressure and high temperatures. The hydrocracker units are not considered fluid catalytic cracking unit catalyst regenerator. Therefore, Hyperion is not subject to this subpart for the hydrocracker units.

Hyperion proposes to construct several process heaters (Unit #1 through #30) that burn fuel gas and a sulfur recovery plant (Unit #42a through #42f) that uses the Claus system to convert hydrogen sulfide into sulfur. Therefore, Hyperion is subject to this subpart for these process heaters and sulfur recovery plant.

The combustion turbines may fall underneath the fuel gas combustion devices. Fuel gas combustion device means any equipment, such as process heaters, boilers and flares used to combust fuel gas. Fuel gas means any gas which is generated at a petroleum refinery and which is combusted.

The five combustion turbines are proposed to burn diesel fuel during startup and syngas and PSA tail gas or natural gas and PSA tail gas as the main fuel. Diesel fuel is not a gas and as such is not considered a fuel gas. The natural gas would not be produced by the petroleum refinery and as such is not considered a fuel gas. The syngas and PSA tail gas may fall underneath the term fuel gas.

On December 1, 1980, EPA amended the definition of fuel gas to the current listing noted above. As noted in the December 1, 1980 federal register of the final rule, the proposed definition was to define fuel gas as "natural gas generated at a petroleum refinery, or any gas generated by a refinery process unit, which is combusted separately or in any combination with any type of natural gas". In the final rule, EPA revised the definition but stated that the intent and substance of the promulgated amendment is the same as the proposed amendment.

The term fuel gas is limited to the gas that is produced by a petroleum refinery process unit. A refinery process unit means any segment of the petroleum refinery in which a specific processing operation is conducted. A petroleum refinery means any facility engaged in producing gasoline, kerosene, distillate fuel oils, residual fuel oils, lubricants, or other products through distillation of petroleum or through re-distillation, cracking or reforming of unfinished petroleum derivatives.

The syngas and PSA tail gas produced by the gasification process of the integrated gasification combined cycle system does not produce the gas using a refinery process unit because it is not an operation that produces gasoline, kerosene, etc. by the process of distillation, cracking or reforming. Therefore, the syngas and PSA tail gas are not considered a fuel gas.

As noted in RTP Environmental Associates' August 20, 2007, letter, the United States Court of Appeals for the Third Circuit made a decision that stated that two combustion turbines that burned syngas produced by a gasification of petroleum coke was not applicable this subpart. The decision was based on if the combustion turbines were or were not part of the refinery. As RTP Environmental Associates indicate in their letter to EPA, the combustion turbines at Hyperion will be considered part of the refinery. The decision does consider other potential positions.

Depending on the gasification process, the type of feedstock, etc., the syngas may have several sulfur compounds in the gas stream such as carbonyl disulfide, dimethyl sulfide, dimethyl disulfide, methyl, mercaptan, ethyl mercaptan, and hydrogen sulfide. Even though the court did not make a formal determination on the definition of fuel gas, the decision does indicate that the chemical composition of the syngas was different than that of fuel gas and as such made EPA's determination appear to be inconsistent with the regulations. As EPA notes in the December 1, 1980 federal register, the intention of the rule was to control sulfur dioxide by controlling the hydrogen sulfide portion in fuel gas streams. This supports the statement that syngas and PSA tail gas are not a fuel gas.

The court decision also indicates that if combustion turbines were regulated under another subpart that EPA did not intend for those types of operations to be covered by this subpart. The five combustion turbines proposed for Hyperion are regulated by 40 CFR Part 60, Subpart Da while burning the syngas and PSA tail gas and 40 CFR Part 60, Subpart KKKK for burning the natural gas and PSA tail gas. Therefore, this also supports the statement that syngas and PSA tail gas are not a fuel gas. Therefore, underneath the scenario presented in the application, the combustion turbines associated with the IGCC system are not applicable to this subpart.

This subpart contains particulate matter, sulfur dioxide, nitrogen oxide and carbon monoxide emission limits. The particulate matter, nitrogen oxide, and carbon monoxide emissions limits apply to a fluid catalytic cracking unit and a fluid coking unit. Hyperion did not propose to construct and operate a fluid catalytic cracking unit or a fluid coking unit. Therefore, only the sulfur dioxide emission limits are applicable to Hyperion and are noted in Table 3-2.

Table 3-2 – 40 CFR Part 60, Subpart J Air Emission Limits

Pollutant (Unit Description)	Citation	NSPS Limit
Sulfur dioxide (Process Heaters)	40 CFR § 60.104(a)(1)	Fuel gas containing greater than 0.10 grains of hydrogen sulfide per dry standard cubic foot
Sulfur dioxide (Sulfur Recovery Plant)	40 CFR § 60.104(a)(2)(i)	250 parts per million by volume (dry basis) sulfur dioxide at zero percent excess air

3.6 Subpart Ja

On May 14, 2007, EPA proposed the Standards of Performance for Petroleum Refineries for Which Construction, Reconstruction or Modification Commenced After May 14, 2007. On June 24, 2008, EPA promulgated this rule in 40 CFR Part 60, Subpart Ja and this rule applies to the following:

1. Each fluid catalytic cracking unit, fluid coking unit, delayed coking unit, process heater, other fuel gas combustion device, and sulfur recovery plant which commenced construction, modification, or reconstruction after May 14, 2007; and
2. Each flare which commenced construction, modification, or reconstruction after June 24, 2008.

Fuel gas means any gas which is generated at a petroleum refinery and which is combusted. DENR considers the fuel gas has the same meaning as fuel gas in 40 CFR Part 60, Subpart J as EPA did not address this issue in the preamble to 40 CFR Part 60, Subpart Ja.

The following units are applicable to this subpart: delayed coking units (Unit #31 through #33), process heaters (Unit #1 through #30), sulfur recovery plant (Unit #42a through #42f), other fuel gas combustion devices (Unit #45a), and flares (Unit #36 through #40). This subpart contains particulate matter, sulfur dioxide, and nitrogen oxide emission limits and flow rate limits. The emission and flow rate limits applicable to Hyperion are noted in Table 3-3.

Table 3-3 – 40 CFR Part 60, Subpart Ja Air Emission Limits

Pollutant (Unit Description)	Citation	NSPS Limit
Sulfur dioxide (Sulfur Recovery Plant)	40 CFR §60.102a(f)(1)	Discharge sulfur dioxide in excess of 250 parts per million by volume (dry basis, corrected to 0% excess air) [1]

Pollutant (Unit Description)	Citation	NSPS Limit
Sulfur dioxide (Process Heaters and Other Fuel Gas Combustion Devices)	40 CFR §60.102a(g)(1)	Discharge sulfur dioxide in excess of 20 parts per million by volume (dry basis, corrected to 0% excess air) [2] and 8 parts per million by volume (dry basis, corrected to 0% excess air) [3] or burn any fuel gas that contains hydrogen sulfide in excess of 162 parts per million by volume [2] and 60 parts per million by volume [3]
Nitrogen oxide (Process Heaters)	40 CFR §60.102a(g)(2)	Discharge nitrogen oxide in excess of 40 parts per million by volume (dry basis, corrected to 0% excess air) [4]
Flare	40 CFR §60.102a(g)(3)	Shall not allow flow to each flare during normal operations of more than 7,080 standard cubic meters per day (250,000 standard cubic feet per day) [5]

[1] – For multiple process trains or release points, the owner or operator shall comply with the 250 parts per million by volume limit for each process train or release point or comply with a flow rate weighted average of 250 part per million by volume for all release points. These limits do not apply during periods of maintenance of the sulfur pit; but periods of maintenance shall not exceed 240 hours per year;
[2] – Determined hourly on a 3-hour rolling average basis;
[3] – Determined daily on a 365 successive day rolling average basis;
[4] – Determined on a 24-hour rolling average basis; and
[5] – Determined on a 30-day rolling average. This does not include periods where the flow is the result of relief valve leakage or other emergency malfunctions.

3.7 ARSD 74:36:07:14 – Subpart Kb

The Standards of Performance for Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels) for which Construction, Reconstruction or Modification Commences after July 23, 1984, are applicable to the following systems:

1. Each storage vessel (tank) that has a capacity to store greater than or equal to 75 cubic meters of a volatile organic liquid; and
2. Each storage vessel (tank) that was constructed, reconstructed, or modified after July 23, 1984.

In accordance with 40 CFR §63.640(n)(2), Group 1 storage vessels located at an oil refinery that were constructed or reconstructed after July 14, 1994, are subject to the National Emission

Standards for Hazardous Air Pollutants from Petroleum Refineries under 40 CFR Part 63, Subpart CC and not this subpart.

The application for Hyperion identifies that most of the storage vessels are considered Group I storage vessels and would not be subject to this subpart. The application identifies that just the three sour storage tanks are applicable to this subpart. Both this subpart and 40 CFR Part 63, Subpart CC requires a control device such as a floating roof for similar type tanks. Due to the similarities and because one subpart supersedes the other, both subparts will be reviewed together.

Subpart Kb requires a control device for tanks greater than 151 cubic meters (~40,000 gallons) that store a liquid with a maximum true vapor pressure greater than 5.2 kilopascals (~0.75 psi). Whereas, 40 CFR Part 63, Subpart CC requires a control device for tanks greater than 151 cubic meters (~40,000 gallons) that store a liquid with a maximum true vapor pressure greater than 3.4 kilopascals (~0.5 psi). Table 3-4 lists which subpart is applicable to which tank identified in the application.

Table 3-4 – 40 CFR Part 60, Subpart Kb and 40 CFR Part 63, Subpart CC Tank Applicability

Description	**Capacity (gallons)**	**Max True Vapor Pressure (psi)** [1]	**Control Device** [2]	**Subpart Kb**	**Subpart CC**
Tank #RF1-1.	21,000,000	6 (11)	IFR	No	Yes
Tank #RF1-2.	21,000,000	6 (11)	IFR	No	Yes
Tank #RF1-3.	21,000,000	6 (11)	IFR	No	Yes
Tank #RF1-4.	21,000,000	6 (11)	IFR	No	Yes
Tank #RF1-5.	21,000,000	6 (11)	IFR	No	Yes
Tank #RF1-6.	21,000,000	6 (11)	IFR	No	Yes
Tank #RF1-7.	21,000,000	6 (11)	IFR	No	Yes
Tank #RF1-8.	21,000,000	6 (11)	IFR	No	Yes
Tank #RF1-9.	21,000,000	6 (11)	IFR	No	Yes
Tank #RF1-10.	21,000,000	6 (11)	IFR	No	Yes
Tank #RP4-1.	8,400,000	11	IFR	No	Yes
Tank #RP4-2.	8,400,000	11	IFR	No	Yes
Tank #RP5-1.	8,400,000	11	IFR	No	Yes
Tank #RP6-1.	8,400,000	11	IFR	No	Yes
Tank #RP6-2.	8,400,000	11	IFR	No	Yes
Tank #RP6-3.	8,400,000	11	IFR	No	Yes
Tank #RP6-4.	8,400,000	11	IFR	No	Yes
Tank #RP6-5.	8,400,000	11	IFR	No	Yes
Tank #RP6-6.	8,400,000	11	IFR	No	Yes
Tank #RP6-7.	8,400,000	11	IFR	No	Yes
Tank #RP7-1.	8,400,000	11	IFR	No	Yes

Description	Capacity (gallons)	Max True Vapor Pressure (psi) [1]	Control Device [2]	Subpart Kb	Subpart CC
Tank #RP8-1.	8,400,000	11	IFR	No	Yes
Tank #RP8-2.	8,400,000	11	IFR	No	Yes
Tank #RP8-3.	8,400,000	11	IFR	No	Yes
Tank #RP8-4.	8,400,000	11	IFR	No	Yes
Tank #RP9-1.	8,400,000	11	IFR	No	Yes
Tank #RP10-1.	8,400,000	0.006 (11)	IFR	No	Yes
Tank #RP10-2.	8,400,000	0.006 (11)	IFR	No	Yes
Tank #RP10-3.	8,400,000	0.006 (11)	IFR	No	Yes
Tank #RP11-1.	8,400,000	0.005 (11)	IFR	No	Yes
Tank #RP11-2.	8,400,000	0.005 (11)	IFR	No	Yes
Tank #RP11-3.	8,400,000	0.005 (11)	IFR	No	Yes
Tank #RP11-4.	8,400,000	0.005 (11)	IFR	No	Yes
Tank #RP11-5.	8,400,000	0.005 (11)	IFR	No	Yes
Tank #RP11-6.	8,400,000	0.005 (11)	IFR	No	Yes
Tank #RP11-7.	8,400,000	0.005 (11)	IFR	No	Yes
Tank #RP11-8.	8,400,000	0.005 (11)	IFR	No	Yes
Tank #RP11-9.	8,400,000	0.005 (11)	IFR	No	Yes
Tank #RP11-10.	8,400,000	0.005 (11)	IFR	No	Yes
Tank #RP11-11.	8,400,000	0.005 (11)	IFR	No	Yes
Tank #IP3-1.	10,500,000	5.2 (11)	IFR	No	Yes
Tank #IP3-2.	10,500,000	5.2 (11)	IFR	No	Yes
Tank #IP4-1.	8,400,000	3 (11)	IFR	No	Yes
Tank #IP5-1.	6,300,000	11	IFR	No	Yes
Tank #IP5-2.	6,300,000	11	IFR	No	Yes
Tank #IP6-1.	8,400,000	3 (11)	IFR	No	Yes
Tank #IP6-2.	8,400,000	3 (11)	IFR	No	Yes
Tank #IP7-1.	14,000,000	1 (11)	IFR	No	Yes
Tank #IP7-2.	14,000,000	1 (11)	IFR	No	Yes
Tank #IP8-1.	6,300,000	1 (11)	IFR	No	Yes
Tank #IP8-2.	6,300,000	1 (11)	IFR	No	Yes
Tank #IP9-1.	4,200,000	1 (11)	IFR	No	Yes
Tank #IP10-1.	2,100,000	1 (11)	IFR	No	Yes
Tank #IP10-2.	2,100,000	1 (11)	IFR	No	Yes
Tank #IP11-1.	8,400,000	3 (11)	IFR	No	Yes
Tank #IP11-2.	8,400,000	3 (11)	IFR	No	Yes
Tank #IP11-3.	8,400,000	3 (11)	IFR	No	Yes
Tank #IP11-4.	8,400,000	3 (11)	IFR	No	Yes
Tank #IP12-1.	8,400,000	1 (11)	IFR	No	Yes

Description	Capacity (gallons)	Max True Vapor Pressure (psi) [1]	Control Device [2]	Subpart Kb	Subpart CC
Tank #IP13-1.	6,300,000	8 (11)	IFR	No	Yes
Tank #IP13-2.	6,300,000	8 (11)	IFR	No	Yes
Tank #IP14-1.	2,500,000	0.4 (11)	IFR	No	Yes
Tank #IP14-2.	2,500,000	0.4 (11)	IFR	No	Yes
Tank #IP15-1.	450,000	0.01 (11)	IFR	No	Yes
Tank #IP16-1.	4,200,000	0.01 (11)	IFR	No	Yes
Tank #IP16-2.	4,200,000	0.01 (11)	IFR	No	Yes
Tank #IP17-1.	4,200,000	0.005 (11)	IFR	No	Yes
Tank #IP17-2.	4,200,000	0.005 (11)	IFR	No	Yes
Tank #IP17-3.	4,200,000	0.005 (11)	IFR	No	Yes
Tank #IP18-1.	4,200,000	0.015	NA	No	Yes, but no control required
Tank #IP19-1.	4,200,000	0.004 (11)	IFR	No	Yes
Tank #IP19-2.	4,200,000	0.004 (11)	IFR	No	Yes
Tank #IP20-1.	8,400,000	0.005 (11)	IFR	No	Yes
Tank #IP20-2.	8,400,000	0.005 (11)	IFR	No	Yes
Tank #IP20-3.	8,400,000	0.005 (11)	IFR	No	Yes
Tank #IP21-1.	2,100,000	1 (11)	IFR	No	Yes
Tank #IP22-1.	8,400,000	0.005 (11)	IFR	No	Yes
Tank #IP22-2.	8,400,000	0.005 (11)	IFR	No	Yes
Tank #IP23-1.	14,000,000	0.015	NA	No	Yes, but no control required
Tank #IP23-2.	14,000,000	0.015	NA	No	Yes, but no control required
Tank #IP23-3.	14,000,000	0.015	NA	No	Yes, but no control required
Tank #IP24-1.	4,200,000	0.009	NA	No	Yes, but no control required
Tank #IP24-2.	4,200,000	0.009	NA	No	Yes, but no control required
Tank #IP25-1.	21,000,000	0.04	NA	No	Yes, but no control required
Tank #IP25-2.	21,000,000	0.04	NA	No	Yes, but no control required
Tank #IP26-1.	150,000	0.5 (11)	IFR	No	Yes
Tank #IP26-2.	150,000	0.5 (11)	IFR	No	Yes
Tank #SS1-1.	3,400,000	2.4 (11)	IFR	No	Yes
Tank #SS1-2.	3,400,000	2.4 (11)	IFR	No	Yes
Tank #SS2-1.	6,300,000	3.3 (11)	IFR	Yes	No

Description	Capacity (gallons)	Max True Vapor Pressure (psi) [1]	Control Device [2]	Subpart Kb	Subpart CC
Tank #SS3-1.	6,300,000	3.3 (11)	IFR	Yes	No
Tank #SS4-1.	6,300,000	3.3 (11)	IFR	Yes	No
Tank #SS8-1.	6,300,000	0.017	NA	No	Yes, but no control required
Tank #SS9-1.	6,300,000	0.0014	IFR	No	Yes, but no control required
Tank #SS10-1.	6,300,000	0.0014	IFR	No	Yes, but no control required
Tank #SS14-1.	150,000	3.3 (11)	IFR	No	Yes
Tank #SS15-1.	150,000	3.3 (11)	IFR	No	Yes
Tank #SS16-1.	150,000	3.3 (11)	IFR	No	Yes
Tank #SS17-1.	150,000	3.3 (11)	IFR	No	Yes
Tank #SS18-1.	150,000	3.3 (11)	IFR	No	Yes
Tank #SS19-1.	150,000	3.3 (11)	IFR	No	Yes
Tank #SS20-1.	150,000	0.0061 (11)	IFR	No	Yes
Tank #SS21-1.	140,000	0.0045 (11)	IFR	No	Yes
Tank #SS22-1.	31,000	1.1 (11)	IFR	No	Yes, but no control required

[1] – Hyperion requested that the tanks be able to store other petroleum products besides the product listed primarily for each tank. Therefore, the vapor pressure in parenthesis notes the highest maximum vapor pressure for any of the petroleum products and is the basis for the review.
[2] – Hyperion proposed an internal floating roof (IFR) or just a fixed roof (NA) to comply with the applicable subparts.

3.8 ARSD 74:36:07:16 – Subpart Y

The Standards of Performance for Coal Preparation Plants are applicable to the following systems:

1. Each thermal dryer, pneumatic coal-cleaning equipment (air tables), coal processing and conveying equipment (including breakers and crushers), coal storage systems and coal transfer and loading systems at a coal preparation plant which process more than 200 tons per day; and
2. Each coal preparation plant that was constructed or modified after October 24, 1974.

Hyperion proposes to construct a coal unloading, conveying, storage and crushing facility (Unit #47). This coal system has the design process rate greater than 200 tons per day and will be constructed after October 24, 1974. Therefore, Hyperion is applicable to this subpart.

Hyperion does not propose to construct a thermal dryer or pneumatic coal cleaning equipment. Therefore, the only emission limit for the system is a 20 percent opacity limit.

3.9 ARSD 74:36:07:18 – Subpart GG

The Standards of Performance for Stationary Gas Turbines are applicable to the following stationary gas turbines

1. All stationary gas turbines with a heat input at peak load equal to or greater than 10.7 gigajoules per hour; and
2. Each stationary gas turbine for which construction, modification, or reconstruction commenced after October 3, 1977.

In accordance with 40 CFR Part 60, Subpart Da, combined cycle gas turbines are exempt from this subpart if the turbines meet the requirements in 40 CFR §60.40Da(b).

In accordance with 40 CFR Part 60, Subpart KKKK, stationary combustion turbines are exempt from this subpart if the turbines meet the requirements of 40 CFR §60.4305(b).

Hyperion proposes to construct and operate five combined cycle gas turbines. Each combined cycle gas turbine is designed to burn diesel fuel during startup and natural gas and PSA tail gas or syngas and PSA tail gas produced from gasification of coal or petroleum coke. Under the natural gas option, the five combined cycle gas turbines are applicable to 40 CFR Part 60, Subpart KKKK and are exempt from this subpart. Under the syngas option, the five combined cycle gas turbines are applicable to 40 CFR Part 60, Subpart Da and are exempt from this subpart.

3.10 ARSD 74:36:07:71 – Subpart UU

The Standards of Performance for Asphalt Processing and Asphalt Roofing Manufacture are applicable to the following:

1. Each saturator, each mineral handling and storage facility at asphalt roofing plants; and each asphalt storage tank and each blowing still at asphalt processing plants, petroleum refineries, and asphalt roofing plants; and
2. Each applicable equipment that was constructed or modified after November 18, 1980.

This standard does not define the term “asphalt”. Therefore, the definition of asphalt was taken from the American Heritage College Dictionary and Webster online dictionary.

The American Heritage College Dictionary defines asphalt as “a brownish-black solid or semisolid mixture of bitumens obtained from native deposits or as a petroleum byproduct, used in paving, roofing, and waterproofing”. The American Heritage College Dictionary defines bitumen as “any various flammable mixtures of hydrocarbons and other substances, occurring naturally or obtained by distillation from coal or petroleum, that are a component of asphalt and tar".

Webster's online dictionary defines asphalt as "a dark bituminous substance that is found in natural beds and is also obtained as a residue in petroleum refining and that consists chiefly of hydrocarbons". Webster's online dictionary defines bituminous as "containing or impregnated with bitumen". Webster's online dictionary defines bitumen as "any of various mixtures of hydrocarbons (as tar) often together with their nonmetallic derivatives that occur naturally or are obtained as residues after heat-refining natural substances (as petroleum) as "containing or impregnated with bitumen".

On May 26, 1981, EPA proposed to amend this proposed rule by clarifying the requirement that the rule applies to any storage tank that stored asphalt for any purpose. The preamble clarifies that the end use of the asphalt was not a consideration for the applicability. The asphalt did not have to be used for paving, roofing, waterproofing, etc. to be applicable to this subpart.

In the application, vacuum residuum was stated to be considered similar to asphalt but no specific information was provided. Vacuum residuum is a hydrocarbon and a brownish-black semisolid mixture. Vacuum residuum is the residue produced from the vacuum distillation process at the petroleum refinery. The vacuum distillation uses heat and pressures below atmospheric pressure to separate the hydrocarbon streams. Therefore, vacuum residuum appears to meet the definition of asphalt.

In EPA's Profile of the Petroleum Refining Industry, the simplified schematic of an oil refinery process indicates that the residue from the vacuum distillation system is either asphalt or a feed stream to a coking process, thermal cracking process, or de-asphalter process. This schematic alludes that vacuum residuum and asphalt are the same material. Hyperion proposes to use the vacuum residuum as the feed stream to the coking process.

Since the vacuum residuum meets the definition of asphalt, EPA clearly identified in the preamble to the rule that the end use of asphalt was not a consideration, and there is no specific process needed to produce asphalt from vacuum residuum, vacuum residuum is considered asphalt. Therefore, Hyperion is applicable to this subpart.

The subpart contains a zero percent opacity requirement for asphalt storage tanks (Unit #154 and #155).

3.11 ARSD 74:36:07:22 – Subpart VV

The Standards of Performance for Equipment Leaks of Volatile Organic Compounds in the Synthetic Organic Chemicals Manufacturing Industry are applicable to the following:

1. Each pump, compressor, pressure relief device, sampling connection system, open-ended valve or line, valves, etc. in the synthetic organic chemicals manufacturing industry; and

2. Each synthetic organic chemical manufacturing industry that was constructed or modified January 5, 1981.

A synthetic organic chemicals manufacturing industry means an industry that produces, as intermediates, or final products, several organic compounds listed in the subpart, such as Acetone, Butadiene, Cumene, Dioxane, Ethanol, Formaldehyde, Glycerol, Phenol, etc.

Hyperion does not produce one of the listed chemicals as an intermediate or final product. Some of the chemicals listed may be found in small quantities in some of the intermediate or final products, such as gasoline. However, these quantities do not qualify those chemicals as being an intermediate or final product because those chemicals are not isolated or not a majority of the product.

Even if this subpart was applicable, this subpart does not apply because Hyperion is subject to 40 CFR Part 63, Subpart CC. 40 CFR §63.640(p) states that if the operations are covered by Subpart CC, the other subparts under Part 60 and 61 are not applicable.

3.12 ARSD 74:36:07:22 – Subpart VVa

The standard was recently promulgated by EPA on November 16, 2007. The Standards of Performance for Equipment Leaks of Volatile Organic Compounds in the Synthetic Organic Chemicals Manufacturing Industry are applicable to the following:

1. Each pump, compressor, pressure relief device, sampling connection system, open-ended valve or line, valves, etc. in the synthetic organic chemicals manufacturing industry; and
2. Each synthetic organic chemical manufacturing industry that was constructed, reconstructed, or modified after November 7, 2006.

A synthetic organic chemicals manufacturing industry means an industry that produces, as intermediates or final products, several organic compounds listed in the subpart, such as Acetone, Butadiene, Cumene, Dioxane, Ethanol, Formaldehyde, Glycerol, Phenol, etc.

Hyperion will be constructed after November 7, 2006; but does not produce any of the listed chemicals as an intermediate or final product. Some of the chemicals listed may be found in small quantities in some of the intermediate or final products, such as gasoline. However, these quantities do not qualify those chemicals as being an intermediate or final product because those chemicals are not isolated or a majority of the product.

Even if this subpart was applicable, this subpart does not apply because Hyperion is subject to 40 CFR Part 63, Subpart CC. 40 CFR §63.640(p) states that if the operations are covered by Subpart CC, the other subparts under Part 60 and 61 are not applicable. In addition, the preamble to the rules states that this rule is not applicable if the facility is applicable to 40 CFR Part 63, Subpart CC.

3.13 ARSD 74:36:07:23 – Subpart XX

The Standards of Performance for Bulk Gasoline Terminals are applicable to the following:

1. Each loading rack at a bulk gasoline terminal which deliver liquid product into gasoline tank trucks; and
2. Each loading rack at a bulk gasoline terminal that was constructed or modified after December 17, 1980.

A bulk gasoline terminal means any gasoline facility which receives gasoline by pipeline, ship or barge, and has a gasoline throughput greater than 75,700 liters per day (~20,000 gallons per day). Hyperion's loading racks may be able to load out more than 75,700 liters per day (~20,000 gallons per day). Therefore, Hyperion is considered a bulk gasoline terminal.

This subpart does not apply because Hyperion is subject to 40 CFR Part 63, Subpart CC. 40 CFR §63.640(r) states that if the operations are covered by Subpart CC, this subpart does not apply.

3.14 ARSD 74:36:07:76 – Subpart GGG

The Standards of Performance for Equipment Leaks of Volatile Organic Compounds in Petroleum Refineries are applicable to each valve, pump, pressure relief device, sampling connection system, compressor, etc. at a petroleum refinery that was constructed or modified after January 4, 1983.

Hyperion will be constructed after January 4, 1983, and will have valves, pumps, etc. However, this subpart does not apply because Hyperion is subject to 40 CFR Part 63, Subpart CC. 40 CFR §63.640(p) states that if the operations are covered by Subpart CC, the other subparts under Part 60 and 61 are not applicable.

3.15 Subpart GGGa

This standard was recently promulgated by EPA on November 16, 2007. The Standards of Performance for Equipment Leaks of Volatile Organic Compounds in Petroleum Refineries are applicable to each valve, pump, pressure relief device, sampling connection system, compressor, etc. at a petroleum refinery that was constructed or modified after November 7, 2006.

Hyperion will be constructed after November 7, 2006, and will have valves, pumps, etc. However, Hyperion is subject to 40 CFR Part 63, Subpart CC. 40 CFR §63.640(p) states that if the valves, pumps, etc. are covered by Subpart CC, the other subparts under Part 60 and 61 are not applicable. In addition, this rule refers to 40 CFR Part 60 Subpart VVa. The preamble to Subpart VVa states the rule is not applicable if the facility is applicable to 40 CFR Part 63 Subpart CC.

3.16 ARSD 74:36:07:78 – Subpart III

The Standards of Performance for Volatile Organic Compound Emissions from Synthetic Organic Chemical Manufacturing Industry Air Oxidation Unit Process are applicable to the following:

1. Each air oxidization reactor that produces one of the listed chemicals (such as acetic acid, acrolein, formaldehyde, etc.) as a product, co-product, by-product, or intermediate; and
2. Each air oxidization reactor that was constructed, modified, or reconstructed after October 21, 1983.

Hyperion does not produce any of the listed chemicals through an air oxidation reactor. Therefore, this subpart does not apply to Hyperion.

3.17 ARSD 74:36:07:26 – Subpart NNN

The Standards of Performance for Volatile Organic Compound Emissions from Synthetic Organic Chemical Manufacturing Industry (SOCMI) Distillation Operations are applicable to the following:

1. Each distillation unit that produces one of the listed chemicals (such as butanes, hexanes, isobutylene, isopentane, propane, etc.) as a product, co-product, by-product, or intermediate; and
2. Each distillation unit that was constructed, modified, or reconstructed after December 30, 1983.

Hyperion will have several distillation systems that produce one of the listed chemicals and will be constructed after December 30, 1983. The systems are the de-ethanizer, de-propanizer, and de-butanizer columns in the gas plant; the stabilizer column in the Penex isomerization system; the stabilizer column in the BenSat system; and the deisobutanizer column, the stabilizer column, and the stripper column in the Butane Conversion system.

Therefore, this subpart does apply to Hyperion. The application identifies that Hyperion will comply with the emission limits in 40 CFR §60.662(a). This subpart contains total organic compound emission limits. This limit would cover the emissions of both volatile organic compounds and hazardous air pollutants. The emission limits are noted in Table 3-5.

Table 3-5 – 40 CFR Part 60, Subpart NNN Air Emission Limits

Pollutant	Citation	NSPS Limit
Total Organic Compounds (less methane and ethane)	40 CFR §60.662(a)	The less stringent of the either: 98 weight-percent reduction; or concentration of 20 parts per million by volume, on a dry basis corrected to 3 percent oxygen [1]

[1] – If a boiler or process heater is used to comply with this subpart, then the vent stream shall be introduced into the flame zone of the boiler or process heater.

This subpart is applicable to processes that produce refinery gas or burn refinery gas.

3.18 ARSD 74:36:07:27 – Subpart OOO

The Standards of Performance for Nonmetallic Mineral Processing Plants are applicable to the following:

1. Each crusher, grinding mill, screening operation, bucket elevator, belt conveyor, bagging operation, storage bin, enclosed truck or railcar loading station at a nonmetallic mineral process plant; and
2. Commenced construction, modification, or reconstruction after August 31, 1983.

A nonmetallic mineral processing plant means any combination of equipment that is used to crush or grind any nonmetallic mineral. A nonmetallic mineral means any of the listed minerals such as sand and gravel; crushed stone such as limestone, gypsum, etc.

Hyperion proposes to use limestone (referenced as flux in the application) in the gasification process. The project will use conveyors, storage bins, milling, etc. associated with the handling of limestone. Therefore, Hyperion is applicable to this subpart.

The subpart contains particulate matter emission limits. The application notes that Hyperion will meet the emission limitation noted in 40 CFR § 60.672(e), which are noted in Table 3-6.

Table 3-6 – 40 CFR Part 60, Subpart OOO Air Emission Limits

Pollutant	NSPS Limit
Particulate matter (Fugitive emissions from buildings)	No visible emissions
Particulate matter (emissions from vents – baghouses)	0.022 grains per dry standard cubic foot and 7 percent opacity

The milling operation will occur within the flux building, which means the visible emission limit for fugitive dust emissions from a building and the baghouse associated with flux building (Unit #48) will be applicable.

3.19 ARSD 74:36:07:82 – Subpart QQQ

The Standards of Performance for Volatile Organic Compound Emissions from Petroleum Refinery Wastewater System are applicable to each drain system, oil-water separator, and aggregate facility at an oil refinery that was constructed, modified, or reconstructed after May 4, 1987.

Hyperion will operate a drain system at the facility. This subpart does not apply because Hyperion is subject to 40 CFR Part 63, Subpart CC. 40 CFR §63.640(o) states that if the operations are covered by Subpart CC, this subpart does not apply.

3.20 ARSD 74:36:07:32 – Subpart RRR

The Standards of Performance for Volatile Organic Compound Emissions from Synthetic Organic Chemical Manufacturing Industry (SOCMI) Reactor Processes are applicable to each reactor process the produces one of the listed chemicals (e.g. acetic acid, butanes, isobutylene, isopentane, and hexanes) as a product, co-product, by-product, or intermediate and was constructed, modified, or reconstructed after June 29, 1990.

Hyperion will have several reactor systems that produce one of the listed chemicals and will be constructed after June 29, 1990. The systems are the isomerization reactors in the Penex system; the saturation reactor in the BenSat system; and the butamer isomerization reactor and the oleflex dehydrogenation reactors in the Butane Conversion system. Therefore, this subpart does apply to Hyperion. The application identifies that Hyperion will comply with the emission limits in 40 CFR §60.702(a).

The subpart contains total organic compound emission limits. This limit would cover the emissions of both volatile organic compounds and hazardous air pollutants. The emission limits are noted in Table 3-7.

Table 3-7 – 40 CFR Part 60, Subpart RRR Air Emission Limits

Pollutant	Citation	NSPS Limit
Total organic compounds (less methane and ethane)	40 CFR §60.702(a)	The less stringent of the either: 98 weight-percent reduction; or concentration of 20 parts per million by volume on a dry basis corrected to 3 percent oxygen [1]

[1] – If a boiler or process heater is used to comply with this subpart, then the vent stream shall be introduced into the flame zone of the boiler or process heater.

3.21 ARSD 74:36:07:88 – Subpart IIII

The Standards of Performance for Stationary Compression Ignition Internal Combustion Engines are applicable to the following:

1. Each stationary compression ignition internal combustion engines that are manufactured after April 1, 2006 and are not fire pump engines, or
2. Each stationary compression ignition internal combustion engines manufactured as a certified National Fire Protection Association (NFPA) fire pump engine after July 1, 2006.

Hyperion proposes to install six new compression ignition internal combustion engines (four generators (Unit #65 through #68) and two fire pumps (Unit #69 and #70)). Therefore, this subpart is applicable to Hyperion.

The subpart contains particulate matter, sulfur dioxide, nitrogen oxides, hydrocarbons (this includes volatile organic compounds) and carbon monoxide emission limits. The emission limits are variable depending on the size and age of each compression ignition internal combustion engine. The emission limits are noted in Table 3-8 for units that would be constructed after 2010 (e.g. starting with the 2011 calendar year) and with a displacement less than 10 liters per cylinder.

Table* 3-8 – *40 CFR Part 60, Subpart IIII Air Emission Limits

Pollutant	Citation	NSPS Limit
Particulate matter (emergency engines)	40 CFR §60.4205(b)	0.20 grams per kilowatt-hour
Particulate matter (fire engines)	40 CFR §60.4205(c)	0.20 grams per kilowatt-hour
Sulfur dioxide (emergency engines)	40 CFR §60.4207(b)	Diesel fuel with a sulfur content less than or equal to 15 parts per million and a minimum cetane index of 40 or a maximum aromatic content of 35 volume percent
Sulfur dioxide (fire engines)	40 CFR §60.4207(b)	Diesel fuel with a sulfur content less than or equal to 15 parts per million and a minimum cetane index of 40 or a maximum aromatic content of 35 volume percent
Nitrogen oxides plus non-methane hydrocarbons (emergency engines)	40 CFR §60.4205(b)	6.4 grams per kilowatt-hour
Nitrogen oxides plus non-methane hydrocarbons (fire engines)	40 CFR §60.4205(c)	6.4 grams per kilowatt-hour
Carbon monoxide (emergency engines)	40 CFR §60.4205(b)	3.5 grams per kilowatt-hour
Carbon monoxide (fire engines)	40 CFR §60.4205(c)	3.5 grams per kilowatt-hour

3.22 ARSD 74:36:07:89 – Subpart KKKK

On August 20, 2007, RTP Environmental Associates requested concurrence from EPA Headquarters that this subpart did not apply to Hyperion during periods when the turbines burned the syngas because Hyperion was applicable to 40 CFR Part 60, Subpart Da. On September 24, 2007, EPA Headquarters responded to RTP Environmental Associates that this request should be directed through South Dakota’s DENR.

The Standards of Performance for Stationary Combustion Turbines are applicable to the following stationary combustion turbines:

1. Each stationary combustion turbine with a heat input at peak load equal to or greater than 10.7 gigajoules (10 MMBtus) per hour; and

2. Each stationary combustion turbine for which construction, modification, or reconstruction commenced after February 18, 2005.

In accordance with 40 CFR 60.40Da(b), a combined cycle gas turbine (both the stationary combustion turbine and any associated duct burners) are subject to 40 CFR Part 60, Subpart Da and not subject to 40 CFR Part 60, Subpart GG or KKKK if:

1. The combined cycle gas turbine is capable of combusting more than 73 megawatts (250 MMBtu/hr) heat input of fossil fuel (either alone or in combination with any other fuel);
2. The combined cycle gas turbine is designed and intended to burn fuels containing 50 percent (by heat input) or more solid-derived fuel not meeting the definition of natural gas on a 12-month rolling average basis; and
3. The combined cycle gas turbine commenced construction, modification, or reconstruction after February 28, 2005.

Hyperion proposes to construct and operate five combined cycle gas turbines. Each combined cycle gas turbine is designed to burn diesel fuel during startup and natural gas and PSA tail gas or syngas or PSA tail gas produced from the gasification of coal or petroleum coke. Under the natural gas option, the five combined cycle gas turbines are applicable to this subpart. Under the syngas option, the five combined cycle gas turbines are applicable to 40 CFR Part 60, Subpart Da and are exempt from this subpart.

This subpart contains sulfur dioxide and nitrogen oxide emission limits. The emission limits are noted in Table 3-9.

Table 3-9 – 40 CFR Part 60, Subpart KKKK Air Emission Limits

Pollutant	Citation	NSPS Limit
Sulfur dioxide	40 CFR §60.4330(a)	Discharge any gases which contain sulfur dioxide in excess of 0.9 pounds per megawatt-hour gross output; or burn any fuel which contains total potential sulfur emission in excess of 0.060 pounds sulfur dioxide per million Btu heat input
Nitrogen oxide – Natural Gas	40 CFR §60.4325 – Table 1	15 parts per million at 15 percent oxygen or 0.43 pounds per megawatt-hour
Nitrogen oxide – Diesel Fuel	40 CFR §60.4325 – Table 1	42 parts per million at 15 percent oxygen or 1.3 pounds per megawatt-hour

4.0 National Emission Standards for Hazardous Air Pollutants

DENR reviewed the national emission standards for hazardous air pollutants (NESHAP) under 40 CFR Part 61 and determined that the following may be applicable to Hyperion.

4.1 ARSD 74:36:08:01 – Subpart A

The General Provisions in 40 CFR Part 61, Subpart A require general requirements for notifications, monitoring, performance testing, reporting, recordkeeping and operation and maintenance. If Hyperion is applicable to a NESHAP, the project is applicable to this subpart. As noted in the following reviews, Hyperion is applicable to a NESHAP and is therefore, applicable to this subpart.

4.2 ARSD 74:36:08:02.01 – Subpart J

The National Emission Standards for Equipment Leaks (Fugitive Emission Sources) of Benzene are applicable to the following:

1. Each pump, compressor, pressure relief device, sampling connection system, open-ended valve or lines, valves, connectors, surge control vessels, bottoms receivers, and control devices that is contact with a fluid that contains equal to or greater than 10 percent benzene; and
2. Each pump, compressor, etc. that is contact with a fluid that contains equal to or greater than 10 percent benzene that is in operation after June 6, 1984.

Hyperion design does not have a process fluid that will contain equal to or greater than 10 percent benzene. Therefore, Hyperion is not applicable to this subpart.

4.3 Subpart Y

The National Emission Standards for Benzene Emissions from Benzene Storage Vessels are applicable to each storage vessel that is storing benzene having a specific gravity within the range of specific gravities specified in ASTM D836-84 for Industrial Grade Benzene, ASTM D835-85 for Refined Benzene-485, ASTM D2359-85a or 93 for Refined Benzene-535 and ASTM D4734-87 or 96 for Refined Benzene-545.

Hyperion does not intend to produce or store benzene as a product. Benzene may be found in small quantities in other products produced at the facility. However, as identified in the ASTM methods, to qualify as an Industrial Grade Benzene, or a Refined Benzene, the product needs to be comprised of 99 percent benzene. Storage vessels storing products containing small quantities of benzene are not considered benzene storage vessels. Therefore, Hyperion is not applicable to this subpart.

4.4 Subpart BB

The National Emission Standards for Benzene Transfer Operations are applicable to the total of all loading racks at which benzene is loaded into tank trucks, railcars, or marine vessels at each benzene production facility and beach bulk terminal. In accordance with 40 CFR §61.300(a), benzene laden waste, gasoline, crude oil, natural gas liquids, petroleum distillates (fuel oil, diesel, or kerosene), or benzene-laden liquid from coke by-product recovery plants are specifically exempted from this subpart.

Hyperion's loading racks will be used to load out gasoline, diesel fuel, etc. Therefore, Hyperion is not applicable to this subpart.

4.5 Subpart FF

On August 20, 2007, RTP Environmental Associates requested concurrence from EPA Headquarters that this subpart applied to the electrical power plant portion of Hyperion. On September 24, 2007, EPA Headquarters responded to RTP Environmental Associates that this request should be directed through South Dakota's DENR.

The National Emission Standards for Benzene Waste Operations are applicable to the following:

1. Each chemical manufacturing plant, coke by-product recovery plant, or a petroleum refinery; or
2. Each hazardous waste treatment, storage, disposal facilities that treat, store, or dispose of hazardous waste from a chemical manufacturing plant, coke by-product recovery plant, or a petroleum refinery; and
3. The waste contains benzene.

Hyperion will operate several processes in the petroleum refinery that will generate waste streams that contain benzene. Therefore, Hyperion is applicable to this subpart.

Hyperion identified in its letter to EPA that the electrical power plant (IGCC system) is considered an integral part of the petroleum refinery. Therefore, the electrical power plant is covered by this subpart. The wastewater treatment facility will treat the water from both the refinery and the IGCC system. The logistics of trying to break down which benzene waste streams are being treated by the refinery or by the IGCC system would be difficult. To simplify the permitting and the applicable requirements, DENR agrees that the IGCC system is applicable to this subpart.

The subpart contains organic hazardous air pollutant emission limits and/or work practice standards. The emission limits are noted in Table 4-1.

Table 4-1 – 40 CFR Part 61, Subpart FF Air Emission Limits

Description	Citation	NESHAP Limit
Storage Tanks	40 CFR §61.343(a)	Install, operate, and maintain a fixed-roof and closed-vent system that routes all organic vapors vented from the tank to a control device; or an enclosure and closed-vent system that routes all organic vapors vented from the tank, located inside the enclosure, to a control device

Description	Citation	NESHAP Limit
Surface Impoundments	40 CFR §61.344(a)(1)	Install, operate, and maintain a cover (e.g., air-supported structure or rigid cover) and closed-vent system that routes all organic vapors vented from the surface impoundment to a control device
Drain Systems	40 CFR §61.346(a)(1)	Install, operate, and maintain a cover and closed-vent system that routes all organic vapors vented from the drain system to a control device.
Treatment Process	40 CFR §61.348(a)	Install, operate, and maintain a treatment process that removes benzene from the waste stream to a level less than 10 parts per million by weight on a flow-weighted annual average basis; or remove 99 percent or more of benzene on a mass basis; or incinerate benzene waste stream with a destruction efficiency of 99 percent or greater
Control Device	40 CFR §61.349(a)(2)	Meets one of the following: at least 95 weight percent reduction of organic compounds; or 98 percent reduction of benzene; or 20 parts per million by volume on a dry basis corrected to 3 percent oxygen; or a flare that meets the requirements of 40 CFR §60.18

5.0 Maximum Achievable Control Technology Standards

In 1990, the United States Congress revised Section 112 of the Clean Air Act. The maximum achievable control technology standards were promulgated based on these revisions. Noted in Section 112(b)(6) of the federal Clean Air Act, the PSD program does not apply to hazardous air pollutants. Even though the hazardous air pollutants are not covered by the PSD program, DENR will review the Maximum Achievable Control Technology (MACT) standards to determine if any apply to Hyperion. In addition, DENR will include a condition in the permit identifying the applicable standard. Hyperion will have to meet these requirements regardless if they are in the PSD permit or not.

DENR reviewed the MACT standards for hazardous air pollutants under 40 CFR Part 63 and determined that the following may be applicable to Hyperion.

5.1 ARSD 74:36:08:03 – Subpart A

The General Provisions in 40 CFR Part 63, Subpart A require general requirements for notifications, monitoring, performance testing, reporting, recording keeping and operation and maintenance. If Hyperion is applicable to a MACT standard, the project is applicable to this subpart. As noted in the following reviews, Hyperion is applicable to MACT standards and is therefore, applicable to this subpart.

5.2 ARSD 74:36:08:03.01 – Subpart B

Requirements for Control Technology Determinations for Major Sources in Accordance with Clean Air Act Sections, Sections 112(g) and 112(j) are applicable to the following:

A major source of hazardous air pollutants that is not covered or exempted from regulation under a standard issued pursuant to sections 112(d) of the Clean Air Act, 112(h) of the Clean Air Act, or that EPA has not promulgated a standard for a specified category by an established deadline.

A major source of hazardous air pollutants is a source that has the potential to emit 10 tons per year or more of a single hazardous air pollutant or 25 tons per year or more of any combination of hazardous air pollutants.

On June 8, 2007, the United States Court of Appeals for the District of Columbia Circuit, vacated 40 CFR Part 63 Subpart DDDDD - National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters. The rule was vacated over an issue involving the applicability of process heaters that would burn a solid fuel. Due to the Court's decision, Hyperion conducted a Case-by-Case MACT determination for the process heaters (Unit #1 through #30).

The Case-by-Case MACT determination considered three broad areas: 1) organic hazardous air pollutants; 2) metal hazardous air pollutants; and 3) inorganic hazardous air pollutants.

The Case-by-Case MACT determination for the organic hazardous air pollutants was good combustion practices. Good combustion practices were also considered in the BACT analysis for carbon monoxide. The BACT review process determines the maximum emission reduction that is achievable taking into account several listed factors. This process is similar to the requirement for a MACT determination. Hyperion proposed to use the limit for carbon monoxide as a surrogate for organic hazardous air pollutants. This approach is consistent with how EPA finalized 40 CFR Part 63 Subpart DDDDD. The proposed carbon monoxide BACT limit for the process heaters (Unit #1 through #30) is more stringent than the limit finalized by EPA.

The Case-by-Case MACT determination for the metal hazardous air pollutants was good combustion practices. Good combustion practices were also considered in the BACT analysis for particulate matter, which would contain the trace metals. Hyperion proposed to use the limit for particulate matter as a surrogate for metal hazardous air pollutants.

The Case-by-Case MACT determination for the inorganic hazardous air pollutants (hydrogen chloride) was fuel gas scrubbing. A performance test will be required to demonstrate compliance with the hydrogen chloride emission limit. The compliance period will be the average of three 1-hour compliance tests.

DENR did not locate or identify a more stringent MACT determination or limitation than that proposed by Hyperion. Table 5-1 identifies the proposed Case-by-Case MACT standards.

Table 5-1 – 40 CFR Part 63, Subpart B Air Emission Limits

Unit	Organic Hazardous Air Pollutants	In-organic Hazardous Air Pollutants	Metal Hazardous Air Pollutants
#1 through #30	BACT for carbon monoxide	Hydrogen chloride limit of 0.0012 pounds per million Btus	BACT for particulate matter

5.3 ARSD 74:36:08:05 – Subpart F

The National Emission Standards for Organic Hazardous Air Pollutants from the Synthetic Organic Chemical Manufacturing Industry are applicable to the following:

1. Each chemical manufacturing facility that manufactures as a primary product one of the listed chemicals (such as acetic acid, cumene, methanol, etc.)

Hyperion does not produce one of the listed chemicals as a primary product. Some of the chemicals listed may be found in small quantities in some of the primary products, such as gasoline. However, these quantities do not qualify those chemicals as being a primary product because those chemicals are not isolated or not a majority of the product. Therefore, Hyperion is not applicable to this subpart.

5.4 ARSD 74:36:08:06 – Subpart G

The National Emission Standards for Organic Hazardous Air Pollutants from the Synthetic Organic Chemical Manufacturing Industry Process Vents, Storage Vessels, Transfer Operations, and Wastewater are applicable to each process vent, storage vessel, transfer rack, wastewater stream, and in process equipment at a chemical manufacturing facility that is applicable to ARSD 74:36:08:05 – 40 CFR Part 63, Subpart F.

As noted above, Hyperion does not produce one of the listed chemicals as a primary product under 40 CFR Part 63, Subpart F. Some of the chemicals listed in 40 CFR Part 63, Subpart F may be found in small quantities in some of the primary products, such as gasoline. However, these quantities do not qualify those chemicals as being a primary product because those chemicals are not isolated or not a majority of the product. Therefore, Hyperion is not applicable to this subpart.

5.5 ARSD 74:36:08:07 – Subpart H

The National Emission Standards for Organic Hazardous Air Pollutants for Equipment Leaks are applicable to the following:

1. Each pump, compressor, pressure relief device, sampling connection system, open-ended valve or line, valves, etc.; and
2. Another subpart references this subpart.

Hyperion will have several pumps, compressors, etc. associated with the operation of the facility that are applicable to 40 CFR Part 63, Subpart CC, which references this subpart in 40 CFR §63.648(a) as a requirement. As noted below, 40 CFR Part 63, Subpart CC is applicable to Hyperion. Therefore, Hyperion is applicable to this subpart.

5.6 ARSD 74:36:08:11 – Subpart Q

The National Emission Standards for Hazardous Air Pollutants for Industrial Process Cooling Towers are applicable to each new and existing industrial process cooling tower that are operated with chromium-based water treatment chemicals. An industrial process cooling tower means any cooling tower that is used to remove heat that is produced as an input or output of a chemical or industrial process, as well as any cooling tower that cools industrial processes in combination with any heating, ventilation, or air condition system.

Hyperion will have an industrial process cooling tower. The federal regulation prohibits the use of chromium based water treatment chemicals in industrial process cooling towers. This rule does not apply provided no chromium based water treatment chemicals are used. The application notes that no chromium based water treatment chemicals will be used. Therefore, Hyperion is not applicable to this subpart.

Even though the rule is not applicable, a condition will be included in the permit to identify that no chromium based water treatment chemicals may be used.

5.7 ARSD 74:36:08:12 – Subpart R

National Emission Standards for Gasoline Distribution Facilities (Bulk Gasoline Terminals and Pipeline Breakout Stations) are applicable to the following:

1. Each new and existing bulk gasoline terminal; and
2. Each new and existing pipeline break station

A bulk gasoline terminal means any gasoline facility which receives gasoline by pipeline, ship or barge, and has a gasoline throughput greater than 75,700 liters per day (~20,000 gallons per day).

Hyperion's loading racks may be able to load out more than 75,700 liters per day (~20,000 gallons per day). Therefore, Hyperion is considered a bulk gasoline terminal. However, this subpart does not apply because Hyperion is applicable to 40 CFR Part 63, Subpart CC. 40 CFR Part 63, Subpart CC does reference this subpart for a portion of its compliance criteria. Therefore, this subpart is not applicable to Hyperion but Hyperion will have to meet the requirements in this subpart that are specified in 40 CFR Part 63, Subpart CC.

5.8 ARSD 74:36:08:50 – Subpart CC

On August 20, 2007, RTP Environmental Associates requested concurrence from EPA Headquarters that this subpart did not apply to the electrical power plant portion of Hyperion because the electrical power plant is not a petroleum refining process unit as defined in the rule. On September 24, 2007, EPA Headquarters responded to RTP Environmental Associates that this request should be directed through South Dakota's DENR.

The National Emission Standards for Hazardous Air Pollutants from Petroleum Refineries are applicable to the following:

1. Each petroleum refining process units;
2. The facility is a major source of hazardous air pollutants; and
3. The facility emits one or more of the listed hazardous air pollutants (such as benzene, ethylbenzene, xylenes, etc.)

A major source of hazardous air pollutants is a source that has the potential to emit 10 tons per year or more of a single hazardous air pollutant or 25 tons per year or more of any combination of hazardous air pollutants.

Hyperion will contain several petroleum refining process units, meets the definition of a major source of hazardous air pollutants, and will emit benzene. Therefore, Hyperion is applicable to this subpart.

A petroleum refining process unit is defined as a process unit used in an establishment primarily engaged in petroleum refining and is used primarily for the following: 1) producing transportation fuels, heating fuels or lubricants; 2) separating petroleum; and 3) separating, cracking, reacting, or reforming intermediate petroleum streams. Examples of such units include, petroleum based solvent units, alkylation units, catalytic hydrotreating, catalytic hydrorefining, catalytic hydrocracking, catalytic reforming, catalytic cracking, crude distillation, lube oil processing, hydrogen production, isomerization, polymerization, thermal processes, and blending, sweetening, treating processes, and sulfur plants.

The electrical power plant (IGCC system) is not considered a petroleum refining process unit. Therefore, DENR agrees that this subpart does not apply to the electrical power plant (IGCC system).

This subpart contains organic hazardous air pollutant or total organic compound emission limits and/or work practice standards. The limits are noted in Table 5-2.

Table 5-2 – 40 CFR Part 63, Subpart CC Air Emission Limits

Pollutant	Citation	MACT Limit
Miscellaneous Process Vents	40 CFR §63.643(a)	Reduce emissions of organic hazardous air pollutant's using a flare that meets the criteria in 40 CFR § 63.11(b); or a control device, by 98 weight-percent or to a concentration of 20 parts per million by volume, on a dry basis, corrected to 3 percent oxygen, whichever is less stringent [1]
Storage Vessels	40 CFR §63.646(a)	Work practice standards
Wastewater	40 CFR §63.647(a)	40 CFR §§61.340 through 61.355
Equipment Leaks	40 CFR §63.648(a)	Work practice standard of a leak, detect and repair program
Gasoline Loading Rack	40 CFR §63.650(a)	40 CFR §§63.421, 63.422 (a) through (c), 63.425 (a) through (c), 63.425 (e) through (h), 63.427 (a) and (b), and 63.428 (b), (c), (g)(1), and (h)(1) through (h)(3) 10 milligrams per liter of gasoline

[1] – Compliance can be determined by measuring either organic hazardous air pollutants or total organic compounds using the procedures in 40 CFR §63.645.

5.9 ARSD 74:36:08:67 - Subpart UUU

On August 20, 2007, RTP Environmental Associates requested concurrence from EPA Headquarters that sulfur recovery plant was applicable to this subpart regardless of whether the sulfur was coming from the petroleum refinery or the electrical power plant (IGCC system). On September 24, 2007, EPA Headquarters responded to RTP Environmental Associates that this request should be directed through South Dakota's DENR.

The National Emission Standards for Hazardous Air Pollutants from Petroleum Refineries – Catalytic Cracking, Catalytic Reforming, and Sulfur Recovery Units are applicable to the following:

1. Each petroleum refinery that is located at a major source of hazardous air pollutant emissions; and
2. Each fluidized catalytic cracking unit, catalytic reforming unit, and each sulfur recovery plant that was constructed, reconstructed, or modified after September 11, 1998.

A major source of hazardous air pollutants is a source that has the potential to emit 10 tons per year or more of a single hazardous air pollutant or 25 tons per year or more of any combination of hazardous air pollutants.

Hyperion will have a catalytic reforming unit and a sulfur recovery plant as part of the petroleum refinery and meets the definition for a major source of hazardous air pollutants. Therefore, Hyperion is applicable to this subpart.

Sulfur is being recovered from the sour water stripper units and amine regeneration units from the petroleum refinery, the gas removal process from the electrical power plant (IGCC system), and other miscellaneous smaller process streams throughout the facility. The sulfur recovery plant associated with the petroleum refinery is an applicable unit under this subpart. There is not a direct way to disassociate the sulfur streams from the petroleum refinery versus the electrical power plant once those streams enter the sulfur recovery plant. Therefore, the sulfur recovery plant regardless of where the sulfur comes from is an applicable unit under this subpart.

The subpart contains organic hazardous air pollutant or total organic compound emission limits or work practice standards. The limits are noted in Table 5-3.

Table 5-3 – 40 CFR Part 63, Subpart UUU Air Emission Limits

Pollutant	Citation	MACT Limit
Catalytic Reforming Units (total organic compounds)	40 CFR §63.1566	A flare that meets 40 CFR §60.18; or the less stringent of 98 percent reduction; or 20 parts per million by volume
Catalytic Reforming Units (hydrogen chloride)	40 CFR §63.1567	The less stringent of 97 percent reduction or 10 parts per million by volume
Sulfur Recovery Plant (sulfur dioxide)	40 CFR §63.1568(a)(i)	250 parts per million by volume
Sulfur Recovery Plant (total reduced sulfur)	40 CFR §63.1568(a)(ii)	300 parts per million by volume

5.10 ARSD 74:36:08:71 - Subpart EEEE

The National Emission Standards for Hazardous Air Pollutants: Non-Gasoline Organic Liquids Distribution are applicable to the following:

1. Each organic liquid distribution (non-gasoline) operation that is a major source of hazardous air pollutants; and
2. Each storage tank, transfer racks, equipment leak component (pump, valve, etc.) at an organic liquid distribution operation.

As defined in 40 CFR §63.2406, organic liquids do not include gasoline (including aviation gasoline), kerosene (No. 1 distillate oil), diesel (No. 2 distillate oil), asphalt, and heavier distillate oils and fuel oils; any fuel consumed or dispensed on-site directly to users (such as fuels for fleet refueling); hazardous waste; wastewater; any non-crude oil liquid with an annual average true vapor pressure less than 0.7 kilopascals (0.1 psia); or any non-crude oil liquid or liquid mixture that contains less than 5 percent of organic hazardous air pollutants.

Hyperion will store liquids such as gasoline, distillate oils, etc. that are specifically listed as liquids that are not covered by this subpart. Therefore, Hyperion is not applicable to this subpart.

5.11 ARSD 74:36:08:72 - Subpart FFFF

On August 20, 2007, RTP Environmental Associates requested concurrence from EPA Headquarters that the Rectisol wash process with the coal gasification process was not applicable to this subpart. On September 24, 2007, EPA Headquarters responded to RTP Environmental Associates that this request should be directed through South Dakota's DENR.

National Emission Standards for Hazardous Air Pollutants from Miscellaneous Organic Chemical Manufacturing are applicable to each miscellaneous organic chemical manufacturing process unit that is located at a major source of hazardous air pollutants. A major source of hazardous air pollutants is a source that has the potential to emit 10 tons per year or more of a single hazardous air pollutant or 25 tons per year or more of any combination of hazardous air pollutants.

A miscellaneous organic chemical manufacturing process unit is defined as "all equipment which collectively functions to produce a product or isolated intermediate that are materials described in the subpart such as methanol, formaldehyde, etc".

Isolated intermediate is defined as "a product of a process that is stored before subsequent processing".

As identified in the application the term "product" is not defined in the rule. The application uses the definition of a product located in 40 CFR Part 63 Subpart F. This subpart defines a product as "a compound or chemical which is manufactured as the intended product of the chemical manufacturing process unit". By-products, isolated intermediates, impurities, wastes and trance contaminants are not considered products.

The American Heritage College Dictionary defines a product as "something produced by human or mechanical effort or by a natural process". This dictionary defines produces as "to manufacture or create economic goods and services; to manufacture". The dictionary also defines manufactures as "to make or process (a raw material) into a finished product; to make or process a product".

Hyperion's application identifies that methanol, which is one of the listed materials, will be used in the Rectisol ® wash process within the coal gasification process. The wash process uses methanol to remove acid gases from the produced gas streams and then recovers the methanol for reuse. This wash process does not use a raw material to produce methanol and does not produce methanol for sale (economic goods). Therefore, the wash process is not a miscellaneous organic chemical manufacturing process.

The rule also alludes under the definition for nondedicated solvent recovery operations that the recovery operation has to be connected with a miscellaneous organic chemical process unit. As noted above, the wash process does not produce methanol as a product. As such, the methanol recovery operation is not considered a chemical manufacturing process unit. Therefore, Hyperion is not applicable to this subpart.

5.12 ARSD 74:36:08:39 - Subpart YYYY

National Emission Standards for Hazardous Air Pollutants for Stationary Combustion Turbines are applicable to each stationary combustion turbine that is located at a major source of hazardous air pollutants. A major source of hazardous air pollutants is a source that has the potential to emit 10 tons per year or more of a single hazardous air pollutant or 25 tons per year or more of any combination of hazardous air pollutants.

The emission and operational limitations apply to those stationary combustion turbine which are a lean premix gas-fired, a diffusion-flame gas-fired, lean premix oil-fired, and a diffusion flame oil-fired. A lean premix gas-fired turbine is each stationary combustion turbine which is equipped to fire gas using lean premix technology and fire oil, where all stationary combustion turbines fire oil no more than a combined 1,000 hours per year. A diffusion-flame gas-fired turbine is each stationary combustion turbine which is equipped to fire gas using diffusion flame technology and fire oil, where all stationary combustion turbines fire oil no more than a combined 1,000 hours per year. A lean premix oil-fired turbine is each stationary combustion turbine which is equipped to fire gas and fire oil using lean premix technology, where all stationary combustion turbines fire oil more than a combined 1,000 hours per year. A diffusion-flame oil-fired turbine is each stationary combustion turbine which is equipped to fire gas and fire oil using diffusion flame technology, where all stationary combustion turbines fire oil more than a combined 1,000 hours per year.

Hyperion meets the definition of a major source of hazardous air pollutants and will have five combustion turbines that will use natural gas, syngas, and diesel as a fuel source.

In the application, the number of hours that the amount of diesel would be used in all the combustion turbines is 500 hours or less per year. As such, the combustion turbines would not be considered a lean premix oil-fired or a diffusion flame oil-fired stationary combustion turbine.

As identified in 40 CFR §63.6095(d), the owner or operator of a lean premix gas-fired or a diffusion-flame gas-fired stationary combustion turbine has to comply with the initial notification requirements but does not have to comply with all the other requirements until EPA takes final action to require compliance and publishes those requirements in the federal register.

Since the application identifies that potential applicability to this subpart, Hyperion has met the initial notification requirements of this subpart. Therefore, no condition associated with this subpart will be included in the permit.

5.13 ARSD 74:36:08:40 - Subpart ZZZZ

National Emission Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines are applicable to each stationary reciprocating internal combustion engine that is located at a major source of hazardous air pollutants. A major source of hazardous air pollutants is a source that has the potential to emit 10 tons per year or more of a single hazardous air pollutant or 25 tons per year or more of any combination of hazardous air pollutants.

Hyperion meets the definition of a major source of hazardous air pollutants and will have four generators and two fire pumps. The application identifies that both the generators and fire pumps will classified as emergency use engines.

As identified in 40 CFR §63.6590(b)(1), the owner or operator that operates a stationary reciprocating internal combustion engine as an emergency engine or limited use engine has to comply with the initial notification requirements but does not have to comply with all the other requirements of the subpart.

Since the application identifies that potential applicability to this subpart, Hyperion has met the initial notification requirements of this subpart. Therefore, no condition associated with this subpart will be included in the permit.

5.14 ARSD 74:36:08:41 - Subpart DDDDD

National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters are applicable to each industrial, commercial, and institutional boiler and process heater that is located at a major source of hazardous air pollutants.

On June 8, 2007, the United States Court of Appeals for the District of Columbia Circuit vacated this rule. Since the rule is currently vacated and the decision identifies that EPA must re-evaluate the requirements, this rule is not applicable to Hyperion.

6.0 New Source Review

ARSD 74:36:10:01 notes that new source review regulations in this chapter apply to areas of the state which are designated as nonattainment pursuant to the Clean Air Act for any pollutant regulated under the Clean Air Act. Hyperion will be located near Elk Point in Union County, South Dakota, which is in attainment for all the pollutants regulated under the Clean Air Act. Therefore, Hyperion is not subject to the new source review requirements in this chapter.

7.0 Prevention of Significant Deterioration

A prevention of significant deterioration (PSD) review applies to new major stationary sources and major modifications to existing major stationary sources in areas designated as attainment under Section 107 of the Clean Air Act for any regulated pollutant.

In accordance with 40 CFR §52.21(b)(50), a "regulated NSR pollutant" means the following:

(1) Any pollutant for which a National Ambient Air Quality Standard has been promulgated and any constituents or precursors for such pollutants identified by the Administrator (e.g., volatile organic compounds and NO_X are precursors for ozone);
(2) Any pollutant that is subject to any standard promulgated under section 111 of the Clean Air Act (Act);
(3) Any Class I or II substance subject to a standard promulgated under or established by Title VI of the Act; or
(4) Any pollutant that otherwise is subject to regulation under the Act; except that any or all hazardous air pollutants either listed in section 112 of the Act or added to the list pursuant to section 112(b)(2) of the Act, which have not been delisted pursuant to section 112(b)(3) of the Act, are not regulated NSR pollutants unless the listed hazardous air pollutant is also regulated as a constituent or precursor of a general pollutant listed under section 108 of the Act.

DENR has received comments on another PSD permit application that methane was a regulated NSR pollutant under the PSD program. Methane is not considered a regulated NSR pollutant under the PSD program because it does not meet the definition of a regulated NSR pollutant as listed above. The following describes why methane does not meet the definition:

- A National Ambient Air Quality Standard has not been promulgated for methane and the Administrator of EPA has not identified methane as a constituent or precursor for an air pollutant with a National Ambient Air Quality Standard. Methane does not meet the requirements under Section (1).
- Under the new source performance standard for landfills (40 CFR Part 60, Subpart Cc and WWW), EPA regulates landfill emissions, which contained methane. The preamble to the final rule for the new source performance standard specifically states that the "regulated NSR pollutant" is the pollutant "MSW Landfill Emissions". This rule defines MSW landfill emissions as "gas generated by the decomposition of organic waste deposited in an MSW landfill or derived from the evolution of organic compounds in the waste. EPA even clarified this intention when it revised the 40 CFR §52.21 and identified the significant threshold for a "regulated NSR pollutant" as MSW landfill emissions (measured as nonmethane organic compounds). Methane does not meet the criteria in Section (2).
- Methane is not listed as a Class I or II substance under or established by Title VI of the Act and does not meet the criteria in Section (3).
- Methane is not subject to another regulation under the Clean Air Act and does not meet the criteria in Section (4).

DENR has received comments on another PSD permit application that carbon dioxide was a regulated NSR pollutant under the PSD program. Carbon dioxide is not considered a regulated NSR pollutant under the PSD program because it does not meet the definition of a regulated NSR pollutant as listed above. The following describes why carbon dioxide does not meet the definition:

- A National Ambient Air Quality Standard has not been promulgated for carbon dioxide and the Administrator of EPA has not identified carbon dioxide as a constituent or precursor for an air pollutant with a National Ambient Air Quality Standard. Carbon dioxide does not meet the criteria in Section (1).
- Under the new source performance standard for landfills (40 CFR Part 60, Subpart Cc and WWW), EPA discusses greenhouse gases, which includes carbon dioxide. The preamble to the final rules discusses that carbon dioxide will increase under the standards but that EPA deemed that acceptable because methane emissions would be reduced and methane contributes considerably more to climate change than carbon dioxide. The pollutants listed as regulated in the preamble are methane and nonmethane organic compounds, not carbon dioxide. The new source performance standard specifically states that the "regulated NSR pollutant" is the pollutant "MSW Landfill Emissions". This rule defines MSW landfill emissions as "gas generated by the decomposition of organic waste deposited in an MSW landfill or derived from the evolution of organic compounds in the waste. EPA even clarified this intention when it revised the 40 CFR 52.21 and identified the significant threshold for a "regulated NSR pollutant" as MSW landfill emissions (measured as nonmethane organic compounds). Carbon dioxide does not meet the criteria in Section (2).
- Carbon dioxide is not listed as a Class I or II substance under or established by Title VI of the Act and does not meet the criteria in Section (3).
- Section 821 of the Clean Air Act and 40 CFR Part 75 requires sources subject to the Acid Rain program to monitor and report carbon dioxide emissions. The carbon dioxide requirement in section 821 of the Act is an information gathering requirement and not a regulated pollutant requirement. Carbon dioxide does not meet the criteria in Section (4).
- Further, the South Dakota Public Utilities Commission (PUC) in issuing a siting permit for the proposed Big Stone II facility specifically found that carbon dioxide emissions are not currently regulated. This decision was upheld by the South Dakota Supreme Court. The South Dakota Supreme Court on January 16, 2008, held that the PUC followed existing legal guidelines in approving the permit, and that its findings, including those regarding carbon dioxide emissions were not erroneous. *In the Matter of Otter Tail Power Company*, 2008 SD 5, ¶¶ 1, 35.

The following is a list of regulated NSR pollutants under the PSD program:

- Total suspended particulate (PM);
- Particulate with a diameter less than or equal to 10 microns (PM10);
- Particulate with a diameter less than or equal to 2.5 microns (PM2.5);
- Sulfur dioxide (SO2);
- Nitrogen oxides (NOx);

- Carbon monoxide (CO);
- Ozone – measured as volatile organic compounds (VOCs);
- Lead;
- Fluorides
- Sulfuric acid mist;
- Hydrogen sulfide;
- Reduced sulfur compounds; and
- Total reduced sulfur.

If the source is considered one of the 28 named PSD source categories listed in Section 169 of the federal Clean Air Act, the major source threshold is 100 tons per year of any regulated pollutant. The major source threshold for all other sources is 250 tons per year of any regulated pollutant.

Hyperion is considered a petroleum refinery, which is one of the 28 named PSD source categories. Once a source is considered major for a given pollutant all the other regulated pollutants are compared to the significant rate threshold to determine if the other regulated pollutants are subject to a PSD review.

Table 7-1 lists the significant rate as defined in 40 CFR §52.21(b)(23) and the potential emissions submitted in the application for Hyperion. As noted in Section 112(b)(6) of the federal Clean Air Act, hazardous air pollutants are not covered by the PSD program.

Table 7-1 – NSR Regulated Air Pollutants Significant Emission Comparison

Pollutant	Uncontrolled Emissions	Controlled Emissions	Significant Rate	PSD Review
PM [1]	Not submitted	1,046 tons/year	25 tons/year	**Yes**
PM10 [2]	Not submitted	1,046 tons/year	15 tons/year	**Yes**
PM2.5 [3]	Not submitted	1,046 tons/year	-	**Yes**
Sulfur dioxide	Not submitted	863 tons/year	40 tons/year	**Yes**
Nitrogen oxide	Not submitted	773 tons/year	40 tons/year	**Yes**
Carbon monoxide	Not submitted	1,999 tons/year	100 tons/year	**Yes**
Ozone (measured as VOC)	Not submitted	473 tons/year	40 tons/year	**Yes**
Lead	Negligible	Not submitted	0.6 tons/year	No
Fluorides [4]	Negligible	Not submitted	3 tons/year	No
Sulfuric acid mist	Not submitted	80 tons/year	7 tons/year	**Yes**
Hydrogen sulfide	Not submitted	25 tons/year	10 tons/year	**Yes**
Reduced sulfur compounds [5]	Not submitted	25 tons/year	10 tons/year	**Yes**
Total reduced sulfur [6]	Not submitted	25 tons/year	10 tons/year	**Yes**

[1] – "PM" means total suspended particulate matter;
[2] – "PM10" means particulate matter 10 microns in diameter or less;
[3] – "PM2.5" means particulate matter 2.5 microns in diameter or less. PM2.5 is a subset of PM10;
[4] – Fluorides is any compound that contains fluorine;

[5] – As defined in 40 CFR Part 60, Subpart J, reduced sulfur compounds means hydrogen sulfide, carbonyl sulfide, and carbon disulfide; and
[6] – As defined in 40 CFR Part 60, Subpart BB, total reduced sulfur means the sum of sulfur compounds, hydrogen sulfide, methyl mercaptan, dimethyl sulfide, and dimethyl disulfide.

Hyperion will have potential emissions of particulate matter, sulfur dioxide, nitrogen oxide, carbon monoxide, ozone (measured as volatile organic compounds), sulfuric acid mist, hydrogen sulfide, reduced sulfur compounds, and total reduced sulfur greater than the "significant rate".

The application did not include air emission increases for lead and fluorides. DENR researched federal documents and did not find any available emission rates for lead, fluorides, or fluorine while burning refinery gas and syngas. DENR considers the fluoride emissions to be negligible. DENR did locate emission factors for lead from burning #6 fuel oil of approximately 0.0000015 pounds per gallon of #6 fuel oil burned. The emissions of lead are estimated to be less than 0.01 tons per year. DENR considers the lead emissions as negligible.

7.1 Best Available Control Technology (BACT) Analysis

In accordance with 40 CFR §52.21(j)(2), a new major source shall apply best available control technology (BACT) for each pollutant subject to regulation under the federal Clean Air Act for which it would result in significant net emissions at the source. Based on Table 7-1, a BACT analysis is required for particulate matter, sulfur dioxide, nitrogen oxide, ozone (measured as volatile organic compounds), carbon monoxide, sulfuric acid mist, hydrogen sulfide, total reduced sulfur and reduced sulfur compounds. The total reduced sulfur and reduced sulfur compounds are primarily composed of hydrogen sulfide. Therefore, these two categories will be included with the hydrogen sulfide discussions.

The BACT requirement applies to each individual new or modified affected emissions unit and pollutant emitting activity at which a net emissions increase would occur. The BACT analysis consists of determining the best available controls and establishing an emissions limit (including a visible emission standard) based on the maximum degree of reduction achievable for each pollutant subject to a regulation under the federal Clean Air Act. The BACT analysis is determined on a case-by-case basis taking into account energy, environmental, and economic impacts, and other costs. BACT is achievable through application of production processes or available methods, systems, and techniques, including fuel cleaning, treatment or innovative fuel combustion techniques for control of such pollutant. In no case shall application of BACT result in an emission limit for any pollutant that would be greater than the emission limit allowed by any applicable standard under 40 CFR Parts 60 and 61. Hyperion considered the requirements of Part 60 and 61 as the minimum requirements in its BACT analysis and proposed BACT that was equivalent or more stringent.

If DENR determines that technological or economic limitations on the application of measurement methodology to a particular emissions unit would make the imposition of an emissions standard infeasible, a design, equipment, work practice, operational standard, or combination thereof, may be prescribed instead to satisfy the requirement for the application of BACT. Such standard shall, to the degree possible, set forth the emissions reduction achievable by the implementation of such design, equipment, work practice or operation, and shall provide for compliance by means which achieve equivalent results.

The PSD regulations do not specify a specific BACT analysis process. Therefore, there are several processes that may be used to determine BACT. In general, an applicant's BACT analysis is based on four steps.

The first step consists of identifying available control options for the pollutant under consideration. Available control options are those air pollution control technologies or techniques with a practical potential for application to the emissions unit and the regulated pollutant under evaluation. Air pollution control technologies and techniques include the application of production process or available methods, systems, and techniques, including fuel cleaning or treatment or innovative fuel combustion techniques for control of the affected pollutant.

The second step consists of evaluating the technical feasibility of the various control options in relationship to the specific unit under consideration. A demonstration of technical infeasibility should be clearly documented and should show, based on physical, chemical, and engineering principles, that technical difficulties would preclude the successful use of the control option on the emissions unit under review.

In the third step, all remaining control techniques identified in step 1 and not eliminated by step 2 are ranked and then listed in order of over all control effectiveness for the pollutant under review. The technically feasible options are reviewed in a top-down approach. A top-down approach means the best control measures will be evaluated first and if they are not feasible, the next best control measure will be evaluated. In this step, the control efficiency, the expected emission rate, the expected emission reduction, and the cost, environmental, and energy impacts for each control option are evaluated.

In the final step, the BACT analysis should focus on the direct impact of the control alternatives for the particular pollutant under review. The top alternative in the BACT analysis should be reviewed to determine whether impacts of unregulated air pollutants or impacts in other media would justify selection of an alternative control option. This process continues until the technology under consideration cannot be eliminated by a source specific environmental, energy, or economic impacts which demonstrate that alternative to be inappropriate as BACT.

DENR considered the following areas in reviewing the applicant's BACT analysis, which are not all inclusive:

1. Hyperion's PSD application;
2. EPA's Reasonably Available Control Technology, Best Available Control Technology and Lowest Achievable Emission Rate Clearinghouse (generally referred to as the RACT/BACT/LAER Clearinghouse or RBLC);
3. PSD permits issued to other petroleum refineries and/or IGCC power plants in other states;
4. PSD permit applications;

5. Rules and regulations in other states;
6. Databases from other government resources; and
7. EPA's technical documents.

7.1.1 BACT Analysis for Particulate Matter

7.1.1.1 Particulate Matter BACT for Process Heaters

Hyperion identified in its application one option for BACT. Table 7-2 identifies the BACT option for small and large process heaters and if the option is considered feasible to install. DENR agreed with the first two steps of the BACT analysis.

Table 7-2 – Particulate Matter Options and Feasibility for Process Heaters

Unit	Description	BACT Options	Feasible Options
#1 through #30	Process heaters	Good combustion practices	Yes

In the application, Hyperion did not rank the BACT options in this case since there is only one option. Since there is only one option, a good combustion practice is the top particulate matter control option for the process heaters.

Table 7-3 identifies Hyperion's proposed control option, the rank of the control option, and the proposed emission limit.

Table 7-3 – Proposed Particulate Matter BACT Control and Limit for Process Heaters

Unit	Description	Proposed Control	Rank	Proposed Limit
#1 through #30	Process heaters	Good combustion practices	#1	0.0075 pounds per million Btus (filterable and condensable)

Based on DENR's review, there are six facilities with equivalent or more stringent limitations than those proposed by Hyperion for good combustion practices. DENR reviewed each of these to verify the BACT emission limit.

A review of Pennsylvania Department of Environmental Protection's technical review for the coker heater project at United Refining dated April 9, 2003, notes that the emission limit was 0.008 pounds per million Btus (page 7). The review does indicate that there is vendor data that supports an emission rate of 0.005 pounds per million Btus. DENR received an email from the Pennsylvania Department of Environmental Protection indicating that most of the project was not completed. Therefore, the limitation of 0.005 pounds per million Btus was not required for a process heater at a refinery.

A review of Alaska Department of Environmental Conservation's Construction permit for the Tesoro Alaska Company's Kenai Refinery issued December 31, 2002, notes the emission rate of

0.005 pounds per million Btus (page 17). The permit identifies the emission rate as an emission factor and not as an emission limit. DENR contacted Alaska Department of Environmental Conservation's Anchorage office about the "emission factor" designation and were informed that the emission rate of 0.005 pounds per million Btus was not an enforceable emission limit. Therefore, this stringent of a limitation was not required for a process heater at the refinery.

A review of Texas Commission on Environmental Quality's permit to Exxon Corporation's Exxon Bay Refinery issued on May 5, 1999, notes that the particulate matter emission limits are for total suspended particulate matter (page 1 through 4 of the maximum allowable emission rates). Total suspended particulate matter is considered to be just the filterable particulate that would be collected on a filter and did not include the condensable fraction. Hyperion's proposed emission limit considers the condensable fraction. A direct comparison between these limits is not valid.

A review of Texas Commission on Environmental Quality's technical review of the PSD permit for Fina Oil & Chemical Company's Port Arthur Refinery issued September 8, 1998, notes that the emission limit for the process heaters is 0.006 pounds per million Btus and includes both filterable and condensable portions of the particulate matter (page 4). The review also notes that heaters are designed to burn natural gas and offgas (refinery fuel gas). The review also indicates that the offgas will have a high hydrogen content. The permit allows the compliance test to be conducted with EPA Method 5 or Method 201A/202. DENR contacted the Texas Commission on Environmental Quality and were informed that the emission rate of 0.006 pounds per million Btus was not an enforceable emission limit. In addition, DENR was informed by email that the performance test requirement for particulate was based on Texas's Method 23, which is similar to EPA's Method 5. EPA's Method 202 is the current promulgated method used to determine the condensable fraction for particulate matter 10 microns or less. Therefore, the limitation proposed by Hyperion compared to Port Arthur Refinery may not be directly compared.

A review of Arizona Department of Environmental Quality's permit for the Arizona Clean Fuels Yuma Refinery issued on September 18, 2006, notes that the emission limit for the process heaters is 0.0075 pounds per million Btus (identified throughout the permit but starting on page 22).

A review of Louisiana Department of Environmental Quality's permits for Citigo Petroleum Corporation's Lake Charles Refinery issued September 20, 2002, notes that the emission limit for the process heaters is approximately 0.0075 pounds per millions Btus (page 19).

DENR's review indicates that good combustion practices are the appropriate control technology choice for particulate matter to represent BACT for the process heaters. In DENR's review, the particulate matter emission limit ranged from 0.005 to 0.008 pounds per million Btus. Although the lowest particulate matter emission limits were 0.005 and 0.006 pounds per million Btus, respectively, the three states that listed these emission limits did not consider it enforceable, was not required, or noted a different compliance method. DENR agrees that the BACT limit should be 0.0075 pounds per million Btus. Demonstrating compliance with the BACT emission limit for particulate matter was not specified by Hyperion for the process heaters. DENR is proposing to demonstrate compliance by a 3-hour average based on a stack performance test.

The BACT emission limit for particulate matter is not applicable during periods of startup, shutdown, or malfunctions. The BACT particulate matter emission limit during these occurrences will be discussed later.

7.1.1.2 Particulate Matter BACT for Catalyst Regenerators

Hyperion identified in its application one option for BACT and identified the option as feasible. Table 7-4 identifies the BACT option for catalyst regenerators and if the option is considered feasible to install. DENR agreed with the first two steps of the BACT analysis.

Table 7-4 – Particulate Matter Options and Feasibility for Catalyst Regenerators

Unit	Description	BACT Options	Feasible Options
#31	Number one platformer catalyst regenerator	Work practice standards	Yes
#32	Number two platformer catalyst regenerator	Work practice standards	Yes
#33	Oleflex catalyst regenerator	Work practice standards	Yes

In the application, Hyperion did not rank the BACT options in this case since there is only one option. Since there is only one option, work practice standard is the top particulate matter control option for catalyst regenerators.

Table 7-5, identifies Hyperion's proposed control option, the rank of the control option, and the proposed emission limit.

Table 7-5 – Proposed Particulate Matter BACT Control and Limit for Catalyst Regenerators

Unit	Description	Proposed Control	Rank	Proposed Limit
#31	Number one platformer catalyst regenerator	Work practice standards	#1	0.01 pounds per hour
#32	Number two platformer catalyst regenerator	Work practice standards	#1	0.01 pounds per hour
#33	Oleflex catalyst regenerator	Work practice standards	#1	0.002 pounds per hour

Based on DENR's review, there is one facility with equivalent or more stringent limitations than those proposed by Hyperion for work practice standards. DENR reviewed the permit to verify the BACT emission limit.

A review of Arizona Department of Environmental Quality's permit for the Arizona Clean Fuels Yuma's Refinery issued September 18, 2006, indicates that Arizona did not establish an emission limit for particulate matter (page 78 and 79).

DENR's review indicates that work practice standards are the appropriate control technology choice for particulate matter to represent BACT for catalyst regenerators. In DENR's review, there were no particulate matter emission limits for catalyst regenerators. DENR agrees with Hyperion's proposed BACT particulate matter emission limits established in Table 7-5 (filterable and condensable) for each unit. Demonstrating compliance with the BACT emission limit for particulate matter was not specified by Hyperion for the process heaters. DENR is proposing to demonstrate compliance by a 3-hour average based on a stack performance test.

The BACT emission limit for particulate matter is not applicable during periods of startup, shutdown, or malfunctions. The BACT particulate matter emission limit during these occurrences will be discussed later.

7.1.1.3 Particulate Matter BACT for Sulfur Recovery Plant

The air emissions from the sulfur recovery plant will be controlled by six thermal oxidizers (Unit #42a, #42b, #42c, #42d, and #42e). Hyperion is proposing to operate a maximum of four thermal oxidizers at one time. As such a minimum of two thermal oxidizers are being installed as a backup.

Hyperion identified in its application several options for BACT and identified which options were considered feasible or infeasible. Table 7-6 identifies the BACT options for a sulfur recovery plant and if the options were considered feasible to install. DENR agreed with the first two steps of the BACT analysis.

Table 7-6 – Particulate Matter Options and Feasibility for Sulfur Recovery Plant

Unit	Description	BACT Options	Feasible Options
#42	Sulfur recovery plant's thermal oxidizer	Good combustion practices	Yes
		No controls	No

In the application, Hyperion did not rank the BACT options in this case since there is only one option. Since there is only one option, a good combustion practice is the top particulate matter control option for the sulfur recovery plant.

Table 7-7, identifies Hyperion's proposed control option, the rank of the control option, and the proposed emission limit.

Table 7-7 – Proposed Particulate Matter BACT Control and Limit for Sulfur Recovery Plant

Unit	Description	Proposed Control	Rank	Proposed Limit
#42	Sulfur recovery plant's thermal oxidizer	Good combustion practices	#1	A combined 11.2 pounds per hour for the system

Based on DENR's review, there are two facilities with equivalent or more stringent limitations than those proposed by Hyperion for good combustion practices. DENR reviewed each of these to verify the BACT emission limit.

A review of Louisiana Department of Environmental Quality's permit to ConocoPhillips Company's Lake Charles Refinery issued on May 19, 2006, indicates that the emission limit is based on a combustion device with a maximum heat input of approximately 40 million Btus per hour (page 19). The 1.5 pounds per hour emission limit equates to approximately 0.0375 pounds per million Btus. After comparing the emission limit based on the heat input, Hyperion's proposed emission limit of 0.0278 pounds per million Btu is more stringent.

A review of Arizona Department of Environmental Quality's permit for the Arizona Clean Fuels Yuma Refinery issued on September 18, 2006, does not establish an emission limit for particulate matter for the sulfur recovery plant (page 206 through 209).

DENR's review indicates that a good combustion practice is the appropriate control technology choice for particulate matter to represent BACT for the sulfur recovery plant. In DENR's review, one facility had an hourly particulate matter emission limit for the sulfur recovery plant more restrictive than the limit proposed by Hyperion; but after comparing the particulate limit to the heat input, Hyperion's limit was more restrictive.

DENR agrees with Hyperion's proposed BACT particulate matter emission limits of 11.2 pounds per hour (filterable and condensable) for the sulfur recovery plant as a whole. DENR will also include a limit of the 0.0055 pounds per long ton sulfur loaded per thermal oxidizer (filterable and condensable) as a BACT particulate matter emission limit to ensure that each thermal oxidizer system is operated properly. The 11.2 pounds per hour limit was divided by the maximum sulfur loading of 2,040 long tons per hour to convert the emission limit to pounds per long ton sulfur. This limit will apply to each thermal oxidizer separately and not a combined limit. Demonstrating compliance with the BACT emission limit for particulate matter was not specified by Hyperion for the process heaters. DENR is proposing to demonstrate compliance by a 3-hour average based on a stack performance test.

The BACT emission limit for particulate matter is not applicable during periods of startup, shutdown, or malfunctions. The BACT particulate matter emission limit during these occurrences will be discussed later.

7.1.1.4 Particulate Matter BACT for IGCC Combustion Turbines

Hyperion's petroleum coke production design by itself is not sufficient to run the power plant at full capacity. Hyperion is proposing a "maximum coke design case" and "natural gas design case" to fire five combined cycle combustion turbines to generate electricity for Hyperion's refinery. Under the "maximum coke design case", the combustion turbines will be fired with syngas and pressure swing adsorption tail gas derived from petroleum coke and/or coal. Also under this scenario, additional petroleum coke or coal will be purchased to produce the additional fuel demand necessary for the power plant. Under both scenarios, distillate oil is a backup fuel.

The "natural gas design case" will burn natural gas and pressure swing adsorption tail gas derived from the petroleum coke and/or coal. Instead of purchasing additional petroleum coke or coal to produce additional pressure swing adsorption tail gas, under the “natural gas design case”, natural gas will be purchased to supplement the fuel demand for the power plant.

Hyperion identified in its application several options for BACT and identified which options were considered feasible or infeasible. Table 7-8 identifies the BACT options for the IGCC combustion turbines and if the options were considered feasible to install. DENR agreed with the first two steps of the BACT analysis.

Table 7-8 – Particulate Matter Options and Feasibility for Combustion Turbines

Unit	Description	BACT Options	Feasible Options
#60 through #64	Combined cycle combustion turbines	Syngas sulfur cleanup by chemical absorption	Yes
		Syngas sulfur cleanup by physical absorption	Yes
		Specifying ultra low sulfur distillate fuel oil as a backup	Yes
		Using a low NOx control strategy that excludes SCR	Yes
		Using a carbon monoxide and volatile organic compound strategy that excludes oxidation catalyst	Yes

In the application, Hyperion combined the options listed in Table 7-8 and ranked the feasible control options, which are displayed in Table 7-9.

Table 7-9 – Top Particulate Matter Control Options for Combustion Turbines

Unit	Description	BACT Options	Rank
#60 through #64	Combined cycle combustion turbines	Syngas sulfur cleanup by physical absorption, specifying ultra low sulfur distillate fuel oil as a backup, and excluding SCR and oxidation catalyst	#1
		Syngas sulfur cleanup by chemical absorption, and specifying ultra low sulfur distillate fuel oil as a backup, and including SCR and oxidation catalyst	#2

Table 7-10 identifies Hyperion’s proposed control option, the rank of the control option, and the proposed emission limit.

Table 7-10 – Proposed Particulate Matter BACT Control and Limit for Combustion Turbines

Unit	Description	Proposed Control	Rank	Proposed Limit
#60 through #64	Combined cycle combustion turbines	Syngas sulfur cleanup by physical absorption and specifying ultra low sulfur distillate fuel oil as a backup	#1	0.022 pounds per million Btus (filterable and condensable)

The syngas sulfur cleanup by physical absorption occurs at the power island acid gas removal system (Unit #59) and is identified as Rectisol® wash.

Based on DENR's review, there are two facilities with equivalent or more stringent limitations than those proposed by Hyperion for the proposed control. DENR reviewed each of these to verify the BACT emission limit.

A review of Illinois EPA's permit for the Christian County Generation facility issued on June 5, 2007, for the integrated gasification combined cycle system notes that the emission limit was 0.009 pounds per million Btus for filterable particulate matter while burning syngas, 0.007 for filterable particulate matter while burning natural gas, 0.0220 pounds per million Btus for filterable and condensable while burning syngas, and 0.0110 pounds per million Btus for filterable and condensable while burning natural gas (page 27).

A review of Kentucky Department of Environmental Protection's Air Quality permit to Cach Creek Generation facility issued on January 17, 2008, for the integrated gasification combined cycle system notes the emission limit was 0.0085 pounds per million Btus for filterable particulate matter while burning syngas, 0.0063 for filterable particulate matter while burning natural gas, 0.0217 pounds per million Btus for filterable and condensable while burning syngas, and 0.0161 for filterable and condensable while burning natural gas (page 2 through 4).

DENR agrees that particulate matter removal from syngas by sulfur cleanup by physical absorption and specifying ultra low sulfur distillate fuel oil as a backup represents BACT for the combustion turbines. DENR agrees with Hyperion that the particulate matter BACT limit be established at 0.022 pounds per million Btus heat input (filterable and condensable).

The PSD program requires at a minimum that the BACT limit be as stringent as an applicable new source performance standard. The combined cycle combustion turbines are subject to 40 CFR Part 60, Subpart Da. The particulate matter emission limit under this subpart is 0.14 pounds per megawatt hour gross energy output or 0.015 pounds per million Btus heat input. This limit is applicable to filterable particulate matter or referred to as total suspended particulate matter. The new source performance standard limit for filterable material is not comparable to the filterable and condensable limit because a comparison is dependent on the percentage of filterable and condensable particulate matter in the air emissions. Therefore, DENR will also establish a filterable particulate matter BACT emission limit.

DENR review indicates that the particulate matter emission limit (filterable) ranges from 0.0085 to 0.009 pounds per million Btus while burning syngas and 0.0063 to 0.007 pounds per million Btus while burning natural gas. Both ranges are more restrictive than the filterable particulate matter limit established in the applicable new source performance standard. DENR is proposing a filterable particulate matter BACT emission limit of 0.009 and 0.006 pounds per million Btus for syngas and natural gas, respectively.

DENR review indicates that the particulate matter emission limit (filterable and condensable) ranges from 0.011 to 0.0161 pounds per million Btus while burning natural gas. DENR is proposing a filterable and condensable particulate matter BACT emission limit of 0.011 pounds per million Btus for natural gas.

Distillate oil is used as a backup fuel. DENR is proposing a filterable limit of 0.015 pounds per million Btus, which is equivalent to the new source performance standard requirement. DENR is proposing to demonstrate compliance by a 3-hour average based on a stack performance test.

The BACT particulate matter emission limit is not applicable during startup, shutdown, or malfunctions. The BACT particulate matter emission limit during these occurrences will be discussed later.

7.1.1.5 Particulate Matter BACT for IGCC Startup Burners

Hyperion is proposing a “maximum coke design case” and “natural gas design case” to fire five combined cycle combustion turbines to generate electricity for the Hyperion’s refinery. Under the “maximum coke design case”, the system will use eight gasifier startup burners fired with natural gas. In this case, only six will operated at one time with two gasifier startup burners are used as a backup. The “maximum natural gas design case”, will use seven gasifier startup burners. In this case, only five will operate at one time and two are used as a backup.

Hyperion identified in its application one option for BACT. Table 7-11 identifies the BACT option for IGCC startup burners and if the option is considered feasible to install. DENR agreed with the first two steps of the BACT analysis.

Table 7-11 – Particulate Matter Options and Feasibility for IGCC Startup Burners

Unit	Description	BACT Options	Feasible Options
#51 through #58	Gasifier startup burners	Pipeline-quality natural gas	Yes

In the application, Hyperion did not rank the BACT options in this case since there is only one option. Since there is only one option, pipeline-quality natural gas is the top particulate matter control option for the IGCC startup burners.

Table 7-12, identifies Hyperion’s proposed control option, the rank of the control option, and the proposed emission limit.

Table 7-12 – Proposed Particulate Matter BACT Control and Limit for IGCC Startup Burners

Unit	Description	Proposed Control	Rank	Proposed Limit
#51 through #58	Gasifier startup burners	Pipeline-quality natural gas	#1	No limit proposed

Based on DENR's review, there are two facilities with equivalent or more stringent limitations than those proposed by Hyperion for the proposed control. DENR reviewed each of these to verify the BACT emission limit.

A review of Kentucky Department of Environmental Protection permit to Cash Creek Generation facility issued on January 17, 2008, for the integrated gasification combined cycle system notes that the emission limit was 0.007 pounds per million Btus while burning natural gas (page 13).

A review of Illinois EPA's permit to Christian County Generation facility issued on June 5, 2007, for the integrated gasification combined cycle system notes the emission rate of 0.007 pounds per million Btus while burning natural gas (page 63).

DENR agrees that burning pipeline-quality natural gas is the appropriate control technology choice to represent BACT for gasifier startup burners. DENR disagrees that a particulate matter BACT emission limit should not be established because of the operation of the gasifier startup burners. In the application, Hyperion describes the amount of time the gasifier startup burners would operate. In each scenario the gasifier startup burners would operate equal to or more than eight hours at a time. A performance test could be conducted during this time period, which would not be due to startup, shutdown, or malfunction of the gasifier startup burner.

DENR's review indicates that the particulate matter emission limit is established at 0.007 pounds per million Btus while burning natural gas. Hyperion's calculations indicate an emission rate of 0.006 pounds per million Btus. DENR is proposing a particulate matter BACT emission limit of 0.006 pounds per million Btus (filterable and condensable). DENR is proposing to demonstrate compliance by a 3-hour average based on a stack performance test.

The BACT particulate matter emission limit is not applicable during startup, shutdown, or malfunctions. The BACT particulate matter emission limit during these occurrences will be discussed later.

7.1.1.6 Particulate Matter BACT for Storage Buildings

Hyperion conducted a BACT analysis for particulate matter from the petroleum coke storage building, coal/coke unloading building, the flux unloading building, and the slag loading building. The BACT analysis was separated into two categories. The first category is the processes inside the building, which is considered the non-fugitive portion. The second category is the processes outside the building, which is considered the fugitive portion and will be discussed later.

Hyperion identified in its application several options for BACT and identified which options were considered feasible or infeasible. Table 7-13 identifies the BACT options for non-fugitive storage buildings and if the options were considered feasible to install. DENR agreed with the first two steps of the BACT analysis.

Table 7-13 – Particulate Matter Options and Feasibility for Non-Fugitive Storage Buildings

Unit	Description	BACT Options	Feasible Options
#46	Petroleum coke storage building	Fabric filter systems	Yes
		High moisture levels in materials	Yes
#47	Coal/coke unloading building	Fabric filter systems	Yes
		High moisture levels in materials	Yes
#48	Flux unloading building	Fabric filter systems	Yes
		High moisture levels in materials	Yes
#49	Slag loading building	Fabric filter systems	Yes
		High moisture levels in materials	Yes

In the application, Hyperion ranked the feasible control options. Table 7-14 identifies the feasible options and DENR's estimated control efficiencies for each option to verify Hyperion's ranking.

Table 7-14 – Top Particulate Matter Control Options for Non-Fugitive Storage Buildings

Unit	Description	BACT Options	Control Efficiency	Rank
#46	Petroleum coke storage building	Fabric filter systems	95 to 99.9% control efficiency [1]	#1
		High moisture levels in materials	70 to 90% control efficiency [2]	#2
#47	Coal/coke unloading building	Fabric filter systems	95 to 99.9% control efficiency [1]	#1
		High moisture levels in materials	70 to 90% control efficiency [2]	#2
#48	Flux unloading building	Fabric filter systems	95 to 99.9% control efficiency [1]	#1
		High moisture levels in materials	70 to 90% control efficiency [2]	#2
#49	Slag loading building	Fabric filter systems	95 to 99.9% control efficiency [1]	#1
		High moisture levels in materials	70 to 90% control efficiency [2]	#2

[1] – Particulates and Fine Dust Removal Processes and Equipment, 1977, page 473, Table 96; and
[2] – *Compilation of Air Pollutant Emission Factors, Volume 1: Stationary Point and Area Sources*, AP-42 Fifth Edition 11.19.1, November 1995, page 11.19.1-5.

Table 7-15, identifies Hyperion's proposed control option, the rank of the control option, and the proposed emission limit.

Table 7-15 – Proposed Particulate Matter BACT Control and Limit for Non-Fugitive Storage Buildings

Unit	Description	Proposed Control	Rank	Proposed Limit
#46	Petroleum coke storage building	Fabric filter systems	#1	0.005 grains per dry standard cubic foot
#47	Coal/coke unloading building	Fabric filter systems	#1	0.005 grains per dry standard cubic foot
#48	Flux unloading building	Fabric filter systems	#1	0.005 grains per dry standard cubic foot
#49	Slag loading building	Fabric filter systems	#1	0.005 grains per dry standard cubic foot

Based on DENR's review, there is one facility and a state rule with an equivalent or more stringent limitation than those proposed by Hyperion for the proposed controls. DENR reviewed each of these to verify the BACT emission limit.

A review of California's South Coast Air Management District's Rule 1158 – Storage, Handling, and Transport or Coke, Coal and Sulfur indicates that unloading operations shall occur in a building and a water spray system or a permitted air pollutant control device (page 1158-4). The rule does not specify an emission limit for the control device.

A review of Arizona Department of Environmental Quality's permit for the Arizona Clean Fuels Yuma Refinery issued on September 18, 2006, notes that the emission limit was 0.005 grains per dry standard cubic foot (page 182 to 184).

DENR's review indicates that a fabric filter is the appropriate control technology choice for particulate matter to represent BACT for non-fugitive storage buildings. DENR agrees with Hyperion's proposed BACT particulate matter emission limit of 0.005 grains per dry standard cubic foot (filterable) for each unit.

Demonstrating compliance with the BACT emission limit for particulate matter was not specified by Hyperion for the baghouses. DENR is proposing to demonstrate compliance by a 3-hour average based on a stack performance test.

The BACT particulate matter emission limit is not applicable during startup, shutdown, or malfunctions. The BACT particulate matter emission limit during these occurrences will be discussed later.

7.1.1.7 Particulate Matter BACT for Generators and Fire Pumps

Hyperion identified in its application several options for BACT and identified which options were considered feasible or infeasible. Table 7-16 identifies the BACT options reviewed for generators and fire pumps and if the options were considered feasible to install. DENR agreed with the first two steps of the BACT analysis.

Table 7-16 – Particulate Matter Options and Feasibility for Generators and Fire Pumps

Unit	Description	BACT Options	Feasible Options
#65 through #70	Emergency generators and fire pumps	NOx adsorb technology in conjunction with catalyzed diesel particulate filters	Yes
		SCR used in conjunction with oxidation catalyst	Yes
		Injection timing retard and exhaust gas recirculation	Yes

In the application, Hyperion ranked the feasible control options. Table 7-17 identifies the feasible options and DENR's estimated control efficiencies for each option to verify Hyperion's ranking.

Table 7-17 – Top Particulate Matter Control Options for Generators and Fire Pumps

Unit	Description	BACT Options	Control Efficiency	Rank
#65 through #70	Emergency generators and fire pumps	NOx adsorb technology in conjunction with catalyzed diesel particulate filters, injection timing retard and exhaust gas recirculation	90% control efficiency [1]	#1
		SCR used in conjunction with oxidation catalyst, injection timing retard and exhaust gas recirculation	80% control efficiency [1]	#2
		Injection timing retard and exhaust gas recirculation	50 to 90% control efficiency [2]	#3

[1] – The emission estimates were derived from the federal register notice of the proposed rules for New Source Performance Standard Subpart IIII (Vol. 71, No. 112 / Monday June 12, 2006); and
[2] – Memorandum from Tanya Parise. Alpha Gamma Technologies, Incorporated to Jaime Pagan, EPA Energy Strategies Group, dated December 18, 2007, Cost Impacts and Emission Reductions Associated with Final NSPS for Stationary SI ICE and NESHAP for Stationary RICE.

Hyperion states in the application that the #1 and #2 ranked option would be cost prohibitive and would reduce the energy efficiency attributable to increased pressure drop and environmental impacts associated with catalyst disposal. Therefore, Hyperion chose the #3 ranked option. Table 7-18, identifies Hyperion's proposed control option, the rank of the control option, and the proposed emission limit.

Table 7-18 – Proposed Particulate BACT Control and Limit for Generators and Fire Pumps

Unit	Description	Proposed Control	Rank	Proposed Limit
#65 through #70	Emergency Generators and Fire Pumps	Injection timing retard and exhaust gas recirculation	#3	New Source Performance Standard Subpart IIII requirement - 0.20 grams per kilowatt-hour

Based on DENR's review, there is one facility with an equivalent or more stringent limitation than those proposed by Hyperion for the proposed controls. DENR reviewed each of these to verify the BACT emission limit.

A review of Arizona Department of Environmental Quality's permit for the Arizona Clean Fuels Yuma Refinery issued on September 18, 2006, notes that the emission limit was 0.20 grams per kilowatt-hour (page 441).

DENR agrees with Hyperion's BACT analysis for generators and fire pumps. However, Hyperion analysis alludes that a 2007 model engine could be purchased which would have higher emission rates than those required for a 2008 model year engine or greater. Hyperion will be able to purchase a 2008 model engine or greater once the permit is issued. Therefore, DENR recommends the BACT be the New Source Performance Standard requirements and require a 2008 or newer model engine be purchased and operated.

7.1.1.8 Particulate Matter BACT for Refinery and Gasification Flares

Due to the proposed control equipment, a BACT analysis for particulate matter was conducted for the refinery flares. In addition, a BACT analysis was conducted for the gasification flare, which will be used for the safe disposal of off-specification syngas that is produced during unit startups, shutdowns and malfunctions and that cannot be routed to the combined cycle combustion turbines, the pressure swing adsorption unit, or to another gasifier.

Hyperion identified in its application several options for BACT and identified which options were considered feasible or infeasible. Table 7-19 identifies the BACT options reviewed for refinery flares and gasification flare and if the options were considered feasible to install. DENR agreed with the first two steps of the BACT analysis.

Table 7-19 – Particulate Matter Options and Feasibility for Refinery/Gasification Flares

Unit	Description	BACT Options	Feasible Options
#36 through #40 and #50	Refinery and gasification flares	Good combustion practices	Yes
		Flare minimization plan	Yes
		No control, emit refinery	Yes

Unit	Description	BACT Options	Feasible Options
		gas and syngas to the ambient air	

In the application, Hyperion ranked the feasible control options, which are displayed in Table 7-20.

Table 7-20 – Top Particulate Matter Control Options for Refinery/Gasification Flares

Unit	Description	Feasible Options	Rank
#36 through #40 and #50	Refinery and gasification flares	Good combustion practices and flare minimization plan	#1
		No control, emit refinery gas and syngas to the ambient air	#2

Table 7-21, identifies Hyperion's proposed control option, the rank of the control option, and the proposed emission limit.

Table 7-21 – Proposed Particulate BACT Control and Limit for Refinery/Gasification Flares

Unit	Description	Proposed Control	Rank	Proposed Limit
#36 through #40 and #50	Refinery and gasification flares	Good combustion practices and flare minimization plan	#1	No proposed limit

Based on DENR's review, there is one facility and two state rules with an equivalent or more stringent limitation than those proposed by Hyperion for the proposed controls. DENR reviewed each of these to verify the BACT emission limit.

A review of California's South Coast Air Management District's Rule 1118 – Control of Emissions from Refinery Flares amended November 4, 2005, specifies a work practice and design requirement for the operations of the flares (pages 1118-5 through 1118-7). The rule does not specify a numerical limit for flares.

A review of California's Bay Area Air Quality Management District's Regulation 12 Rule 11 – Flare Monitoring at Petroleum Refineries and Regulation 12 Rule 12 – Flares at Petroleum Refineries, specifies a work practice and design requirement for the operations of the flares (12-12-3). The rule does not specify a numerical limit for flares.

A review of Arizona Department of Environmental Quality's permit for the Arizona Clean Fuels Yuma Refinery issued on September 18, 2006, specifies a work practice and design requirements for the operations of the flares (page 401 through 407).

DENR's review indicates that good combustion practices and a flare minimization plan is the appropriate control technology choice for particulate matter to represent BACT for refinery and gasification flares. The operations of a flare are not conducive to conduct a performance test.

Therefore, DENR agrees with Hyperion that a numerical particulate matter emission limit is not feasible to implement.

7.1.1.9 Particulate Matter BACT for Cooling Tower

Hyperion identified in its application several options for BACT and identified which options were considered feasible or infeasible. Table 7-22 identifies the BACT options reviewed for a cooling tower and if the options were considered feasible to install. DENR agreed with the first two steps of the BACT analysis.

Table 7-22 – Particulate Matter Options and Feasibility for Cooling Tower

Unit	Description	BACT Options	Feasible Options
#41	Cooling tower	Fan air coolers	Yes
		Dry cooling towers	No
		High efficiency drift eliminators on wet cooling towers	Yes
		No control	Yes

The dry cooling tower was not considered feasible because of the achievable temperature delta between the air and cooling water will not achieve the designed cooling water temperature. In the application, Hyperion ranked the feasible control options, which are displayed in Table 7-23.

Table 7-23 – Top Particulate Matter Control Options for Cooling Tower

Unit	Description	Feasible Options	Estimated Emission Rates	Rank
#41	Cooling tower	Fan air cooler and wet cooling tower with high efficiency drift eliminators	0.0005% of water flow rate [1]	#1
		No control	0.02% of water flow rate [1]	#2

[1] – Hyperion application

Table 7-24, identifies Hyperion's proposed control option, the rank of the control option, and the proposed emission limit.

Table 7-24 – Proposed Particulate Matter BACT Control and Limit for Cooling Tower

Unit	Description	Proposed Control	Rank	Proposed Limit
#41	Cooling tower	Fan air cooler and wet cooling tower with high efficiency drift eliminators	#1	0.0005% of water flow rate

Based on DENR's review, there is one facility with an equivalent or more stringent limitation than those proposed by Hyperion for the proposed controls. DENR reviewed each of these to verify the BACT emission limit.

A review of Arizona Department of Environmental Quality's permit for the Arizona Clean Fuels Yuma Refinery issued on September 18, 2006, specifies a high efficiency drift eliminator with the drift criteria of 0.0005% (page 426) of the circulating water flow rate.

DENR's review indicates that a fan air cooler and wet cooling tower with high efficiency drift eliminators is the appropriate control technology choice for particulate matter to represent BACT for a cooling tower. DENR agrees with Hyperion that the proposed BACT particulate matter emission limit should be 0.0005% of the water flow rate.

7.1.1.10 Particulate Matter BACT for Wastewater Treatment Plant

The technology chosen in Hyperion's BACT analysis for the wastewater treatment plant resulted in a BACT analysis for particulate matter emissions. Hyperion identified in its application several options for BACT and identified which options were considered feasible or infeasible. Table 7-25 identifies the BACT options reviewed for the wastewater treatment plant and if the options were considered feasible to install. DENR agreed with the first two steps of the BACT analysis.

Table 7-25 – Particulate Matter Options and Feasibility for Wastewater Treatment Plant

Unit	Description	BACT Options	Feasible Options
#45a	Wastewater treatment's thermal Oxidizer	Good combustion practices	Yes
		No controls	Yes

In the application, Hyperion ranked the feasible control options, which are displayed in Table 7-26.

Table 7-26 – Top Particulate Matter Control Options for Wastewater Treatment Plant

Unit	Description	Feasible Options	Rank
#45a	Wastewater treatment's thermal oxidizer	No control (e.g. no thermal oxidizer)	#1
		Good combustion practices	#2

The "no control" option was ranked #1 because there would be no particulate matter emissions if the thermal oxidizer was not installed to control volatile organic compound emissions from the wastewater treatment plant. The #1 options would not be environmental beneficial since controlling the volatile organic compounds emissions out weighs the slight increase in particulate emissions generated from the thermal oxidizer. Therefore, Hyperion chose the #2 ranked option. Table 7-27, identifies Hyperion's proposed control option, the rank of the control option, and the proposed emission limit.

Table 7-27 – Proposed Particulate Matter BACT Control and Limit for Wastewater Treatment

Unit	Description	Proposed Control	Rank	Proposed Limit
#45a	Wastewater treatment's thermal oxidizer	Good combustion practices	#2	No proposed limit

Based on DENR's review, there is one facility with an equivalent or more stringent limitation than those proposed by Hyperion for the proposed controls. DENR reviewed each of these to verify the BACT emission limit.

A review of Arizona Department of Environmental Quality's permit for the Arizona Clean Fuels Yuma Refinery issued on September 18, 2006, does not establish an emission limit for particulate matter for the thermal oxidizer controlling emissions from the wastewater treatment plant (page 348).

Although there is no established BACT limit for particulate matter emitted from a thermal oxidizer controlling air emissions from a wastewater treatment plant at a refinery, DENR is proposing an emission limit of 0.0075 pounds per million Btus (filterable and condensable). This limit was derived from the thermal oxidizer associated with the tank farm in the Arizona Clean Fuels Refinery permit (page 266). DENR is proposing to demonstrate compliance by a 3-hour average based on a stack performance test.

The BACT particulate matter emission limit is not applicable during startup, shutdown, or malfunctions. The BACT particulate matter emission limit during these occurrences will be discussed later.

7.1.1.11 Particulate Matter BACT for Coke Drum Steam Vents

After the coking process is completed, the coke drums are steamed out and cooled. Once the cooling process has completed, the coke drum is depressurized to the atmosphere through a steam vent. Hyperion conducted a BACT analysis during the periods when the coke drum is depressurized to the atmosphere.

Hyperion identified in its application several options for BACT and identified which options were considered feasible or infeasible. Table 7-28 identifies the BACT options reviewed for the coke steam vents and if the options were considered feasible to install. DENR agreed with the first two steps of the BACT analysis.

Table 7-28 – Particulate Matter Options and Feasibility for Coke Drum Steam Vents

Unit	Description	BACT Options	Feasible Options
#34 and #35	Coke drum steam vents	Design requirement of 2 pounds per square inch, gauged	No
		Design requirement of 5 pounds per square inch, gauged	Yes

Hyperion notes that EPA recently made a determination in the May 14, 2007, preamble to the proposed rules under 40 CFR Part 60, Subpart Ja that it is technically infeasible to recover the coke drum blow down vapors at a drum pressure less than 5 pounds per square inch, gauged (page 27197). In the application, Hyperion did not rank the BACT options in this case since there is only one feasible option. Since there is only one option, the design requirement of 5 pounds per square inch, gauged, is the top particulate matter control option for the coke drum steam vents.

Table 7-29, identifies Hyperion's proposed control option, the rank of the control option, and the proposed emission limit.

Table 7-29 – Proposed Particulate BACT Control and Limit for Coke Drum Steam Vents

Unit	Description	Proposed Control	Rank	Proposed Limit
#34 and #35	Coke drum steam vents	Design requirement of 5 pounds per square inch, gauged	#1	Work design practice standards in accordance with 40 CFR Part 60, Subpart Ja

A review of the Arizona Department of Environmental Quality's permit for the Arizona Clean Fuels Refinery does not specify a standard for the coke drum de-pressuring vents.

Based on DENR's review, there is no facility with an equivalent or more stringent limitation than those proposed by Hyperion for the proposed controls. For example, a review of Arizona Department of Environmental Quality's permit for the Arizona Clean Fuels Yuma Refinery issued on September 18, 2006, does not specify a standard for the coke drum de-pressuring vents.

DENR's review indicates that the design requirement that each coke drum be depressurized to 5 pounds per square inch, gauged, before the exhaust gases can be vented to atmosphere is the appropriate control technology choice for particulate matter to represent BACT for a coke drum steam vents. DENR agrees with Hyperion that the proposed BACT particulate matter emission limit should be based on the work practice standards outlined in 40 CFR Part 60, Subpart Ja.

7.1.1.12 Particulate Matter BACT for Tank Farm Thermal Oxidizer

Hyperion conducted a BACT analysis for the Tanks for volatile organic compounds. DENR disagreed that a thermal oxidizer was not considered BACT for controlling most of the storage tanks. Due to the control technology recommended by DENR, DENR also conducted a BACT review for a thermal oxidizer. DENR based its review on Hyperion's BACT analysis for the thermal oxidizers for the wastewater treatment facility and the following areas, which are not all inclusive:

Table 7-30 identifies the BACT options reviewed for tank farm and if the options were considered feasible to install.

Table 7-30 – Particulate Matter Options and Feasibility for Tank Farm

Unit	Description	BACT Options	Feasible Options
#71 through #174	Tank farm's thermal Oxidizer	Good combustion practices	Yes
		No controls	Yes

DENR ranked the feasible control options based on Hyperion's BACT analysis for the wastewater treatment plant and sulfur recovery plant, which are displayed in Table 7-31.

Table 7-31 – Top Particulate Matter Control Options for Wastewater Treatment Facility

Unit	Description	Feasible Options	Rank
#71 through #174	Tank farm's thermal oxidizer	No control (e.g. no thermal oxidizer)	#1
		Good combustion practices	#2

The "no control" option was ranked #1 because there would be no particulate matter emissions if the thermal oxidizer was not installed to control volatile organic compound emissions from the tank farm. The #1 options would not be environmental beneficial since controlling the volatile organic compounds emissions out weighs the slight increase in particulate emissions generated from the thermal oxidizer. Therefore, DENR chose the #2 ranked option. Table 7-32, identifies DENR's proposed control option, the rank of the control option, and the proposed emission limit.

Table 7-32 – Proposed Particulate Matter BACT Control and Limit for Tank Farm

Unit	Description	Proposed Control	Rank	Proposed Limit
#71 through #174	Tank farm's thermal oxidizer	Good combustion practices	#2	0.0075 pounds per million Btus (filterable and condensable)

Based on DENR's review, there is one facility with an equivalent or more stringent limitation than those proposed by Hyperion for the proposed controls for the thermal oxidizer at a wastewater treatment facility.

A review of Arizona Department of Environmental Quality's permit for the Arizona Clean Fuels Yuma Refinery issued on September 18, 2006, establishes an emission limit of 0.0075 pounds per million Btus for particulate matter (page 266).

DENR is proposing to demonstrate compliance by a 3-hour average based on a stack performance test.

The BACT particulate matter emission limit is not applicable during startup, shutdown, or malfunctions. The BACT particulate matter emission limit during these occurrences will be discussed later.

7.1.1.13 Particulate Matter BACT for Fugitive Sources

Hyperion conducted a BACT analysis for fugitive dust (particulate matter) from sources such as the coker drums, the vehicle traffic associated with loading racks, and the material handling buildings. Hyperion identified in its application one option for BACT and identified the option as feasible. Table 7-33 identifies the BACT option for fugitive dust sources and if the option is considered feasible to implement. DENR agreed with the first two steps of the BACT analysis.

Table 7-33 – Particulate Matter Options and Feasibility for Fugitive Sources

Description	BACT Options	Feasible Options
Fugitive dust sources	Work practice standards	Yes

In the application, Hyperion did not rank the BACT options in this case since there is only one option. Since there is only one option, work practice standard is the top particulate matter control option for fugitive sources. Table 7-34, identifies Hyperion's proposed control option, the rank of the control option, and the proposed emission limit.

Table 7-34 – Proposed Particulate Matter BACT Control and Limit for Fugitive Sources

Description	Proposed Control	Rank	Proposed Limit
Fugitive dust sources	Work practice standards	#1	No proposed limit

For this size of project, DENR considers its National Events Action Policy for the Rapid City area as the minimum requirements for BACT for fugitive dust sources at Hyperion. In most cases, Hyperion proposed similar controls as required by National Events Action Policy. In addition, DENR will require that most of these fugitive dust controls be implemented during the construction phase of the project. Due to requiring these controls during the construction and operational phases of the project, the cost analysis provided in the application for some of the invalidated controls is not representative.

7.1.2 BACT Analysis for Sulfur Dioxide

7.1.2.1 Sulfur Dioxide BACT for Process Heaters

Hyperion identified in its application several options for BACT and identified which options were considered feasible or infeasible. Table 7-35 identifies the BACT options reviewed for small and large process heaters and if the options were considered feasible to install. DENR agreed with the first two steps of the BACT analysis.

Table 7-35 – Sulfur Dioxide Options and Feasibility for Process Heaters

Unit	Description	BACT Options	Feasible Options
#1 through #30	Process heaters	Fuel gas cleanup by chemical absorption	Yes
		Fuel gas cleanup by physical absorption	Yes
		Flue gas desulfurization	Yes

In the application, Hyperion ranked the feasible control options, which are displayed in Table 7-36.

Table 7-36 – Top Sulfur Dioxide Control Options for Process Heaters

Unit	Description	Feasible Options	Estimated Emission Rates	Rank
#1 through #30	Process heaters	Fuel gas cleanup by physical absorption		
		a. Rectisol	a. 0.0001 pounds per million Btus	#1
		b. Selexol	b. 0.001 pounds per million Btus	#2
		Fuel gas cleanup by chemical absorption	0.0046 pounds per million Btus	#3
		Flue gas desulfurization	0.008 pounds per million Btus	#4

Hyperion determine that the installation of fuel gas cleanup by physical absorption using Rectisol or Selexol was cost prohibitive at $75,000 per ton and $35,000 per ton, respectively. Table 7-37, identifies Hyperion's proposed control option, the rank of the control option, and the proposed emission limit.

Table 7-37 – Proposed Sulfur Dioxide BACT Control and Limit for Process Heaters

Unit	Description	Proposed Control	Rank	Proposed Limit
#1 through #20	Large process heaters	Fuel gas cleanup by chemical absorption	#3	35 parts per million by volume refinery gas determined as sulfur [1]
#21 through #30	Small process heaters	Fuel gas cleanup by chemical absorption	#3	35 parts per million by volume refinery gas determined as sulfur [1]

[1] – Compliance is based on a 24-hour rolling average, excluding startups, shutdowns, and malfunctions. Compliance is based on a 365-day rolling average, including startups, shutdowns, and malfunctions.

Based on DENR's review, there are at five facilities and one rule with equivalent or more stringent limitations than those proposed by Hyperion for the proposed controls. DENR reviewed each of these to verify the BACT emission limit.

A review of California's South Coast Air Management District's Rule 431.1 – Sulfur Content of Gaseous Fuels notes the sulfur content of refinery gas is limited to 40 parts per million as hydrogen sulfide (page 431.1-3).

A review of Texas Commission on Environmental Quality's technical review for the permit to Exxon Corporation's Exxon Bay Refinery issued on May 5, 1999, indicates the project was not required to conduct a PSD review for sulfur dioxide (page 3). However, the permit does specify under the special conditions section (page 2) of the permit, that the hydrogen sulfide content of the fuel gas is limited to 25 parts per million. Hydrogen sulfide is one of several sulfur bearing compounds in the fuel gas.

A review of Texas Commission on Environmental Quality's technical review of the PSD permit for Fina Oil & Chemical Company's Port Arthur Refinery issued September 8, 1998, notes the emission limit was based on the 40 CFR Part 60, Subpart J, which limits the hydrogen sulfide in the fuel gas to 0.1 grains per dry standard cubic foot or approximately 160 parts per million as hydrogen sulfide (page 4).

A review of Arizona Department of Environmental Quality's permit for the Arizona Clean Fuels Yuma Refinery issued on September 18, 2006 notes that the emission limit for the process heaters is 35 parts per million as hydrogen sulfide (identified throughout the permit but starting on page 21).

A review of Louisiana Department of Environmental Quality's permit for Conoco Phillips's Alliance Refinery issued on October 3, 2003, notes the emission limit was based on 40 CFR Part 60, Subpart J, which limits the hydrogen sulfide in the fuel gas to 0.1 grains per dry standard cubic foot or approximately 160 parts per million hydrogen sulfide. (page 4).

A review of Louisiana Department of Environmental Quality's permit for Marathon Petroleum Company's Garyville Refinery issued on December 27, 2006, notes the emission limit for sulfur dioxide is to limit the sulfur content reported as hydrogen sulfide in the fuel gas to less than 25 parts per million (page 5). DENR spoke with Louisiana's Department of Environmental Quality and confirmed that this sulfur content limit represents total sulfur and not just hydrogen sulfide.

DENR agrees that fuel gas cleanup by physical absorption was not cost effective. In addition, DENR did not locate a refinery that required this type of system to be used to burn refinery or fuel gas. DENR review indicates that the fuel gas cleanup by chemical absorption is the appropriate control technology choice to represent BACT for the process heaters. However, DENR disagrees that the emission limit proposed for chemical absorption represents an appropriate BACT sulfur dioxide emission limit.

In DENR's review, the emission limit was based on the hydrogen sulfide content in the refinery gas and ranged from 25 to 160 parts per million. DENR is proposing a BACT emission limit reported as hydrogen sulfide of no greater than 25 parts per million of total sulfur in the refinery gas. DENR agrees with the compliance mechanism proposed by Hyperion. Compliance will be based on a 24-hour rolling average, excluding startups, shutdowns, and malfunctions and 365-day rolling average, including startups, shutdowns, and malfunctions.

7.1.2.2 Sulfur Dioxide BACT for Catalyst Regenerators

Hyperion identified in its application several options for BACT and identified which options were considered feasible or infeasible. Table 7-38 identifies the BACT options reviewed for the catalyst regenerators and if the options were considered feasible to install. DENR agreed with the first two steps of the BACT analysis.

Table 7-38 – Sulfur Dioxide Options and Feasibility for Catalyst Regenerators

Unit	Description	BACT Options	Feasible Options
#31	Number one platformer catalyst regenerator	Wet limestone scrubbing	No
		Work practice standards	Yes
#32	Number two platformer catalyst regenerator	Wet limestone scrubbing	No
		Work practice standards	Yes
#33	Oleflex catalyst regenerator	Wet limestone scrubbing	No
		Work practice standards	Yes

Hyperion indicated that the wet limestone scrubbing device was not technically feasible because the regenerators are very small units with exhaust gas flows similar to boilers with a heat input ranging from one to eight million Btus per hour. Since there is only one option, work practice standard is the top sulfur dioxide control option for catalyst regenerators. Table 7-39, identifies Hyperion's proposed control option, the rank of the control option, and the proposed emission limit.

Table 7-39 – Proposed Sulfur Dioxide BACT Control and Limit for Catalyst Regenerators

Unit	Description	Proposed Control	Rank	Proposed Limit
#31	Number one platformer catalyst regenerator	Work practice standards	#1	0.2 pounds per hour
#32	Number two platformer catalyst regenerator	Work practice standards	#1	0.2 pounds per hour
#33	Oleflex catalyst regenerator	Work practice standards	#1	0.03 pounds per hour

Based on DENR's review, there is no facility with equivalent or more stringent limitations than those proposed by Hyperion for the proposed controls. For example, a review of Arizona Department of Environmental Quality's permit for the Arizona Clean Fuels Yuma Refinery issued on September 18, 2006, does not establish an emission limit for sulfur dioxide for the catalyst regenerators (page 78 and 79).

DENR review indicates that the work practice standard is the appropriate control technology choice to represent BACT for the catalyst regenerators. DENR agrees with the emission limits proposed for catalyst regenerators identified in Table 7-39. Demonstrating compliance with the BACT emission limit for sulfur dioxide was not specified by Hyperion for the catalyst regenerators. In this situation, DENR recommends that compliance would be demonstrated by a 3-hour average based on a stack performance test.

The BACT emission limit for sulfur dioxide is not applicable during periods of startup, shutdown, or malfunctions. The BACT sulfur dioxide emission limit during these occurrences will be discussed later.

7.1.2.3 Sulfur Dioxide BACT for Sulfur Recovery Plant

The air emissions from the sulfur recovery plant will be controlled by six thermal oxidizers (Unit #42a, #42b, #42c, #42d, and #42e). Hyperion is proposing to operate a maximum of four thermal oxidizers at one time. As such, a minimum of two thermal oxidizers are being installed as a backup.

Hyperion identified in its application several options for BACT and identified which options were considered feasible or infeasible. Table 7-40 identifies the BACT options reviewed for the sulfur recovery plant and if the options were considered feasible to install. DENR agreed with the first two steps of the BACT analysis.

Table 7-40 – Sulfur Dioxide Options and Feasibility for Sulfur Recovery Plant

Unit	Description	BACT Options	Feasible Options
#42	Sulfur recovery plant's thermal oxidizer	Claus reactor	Yes
		Claus reactor and tail gas treater	Yes
		Claus reactor and thermal oxidizer	Yes
		Claus reactor, tail gas treater, and thermal oxidizer	Yes
		Claus reactor, thermal oxidizer, and wet scrubber	Yes
		No Control	Yes

In the application, Hyperion ranked the feasible control options based on the control efficiency of the option, which is displayed in Table 7-41.

Table 7-41 – Top Sulfur Dioxide Control Options for Sulfur Recovery Plant

Unit	Description	Feasible Options	Control Efficiency	Rank
#42	Sulfur recovery plant's thermal oxidizer	No control	100%	#1
		Claus reactor, tail gas treater, and thermal oxidizer	99.97%	#2
		Claus reactor, thermal oxidizer, and wet scrubber	99.94%	#3
		Claus reactor and tail gas treater	99%	#4
		Claus reactor and thermal oxidizer	99%	
		Claus Reactor	98%	#5

The sulfur dioxide emissions are generated in the process to control hydrogen sulfide emissions. DENR agrees that controlling the hydrogen sulfide emissions outweighs the impact of generating sulfur dioxide from the process. Therefore, DENR agrees that "no control" does not represent BACT for sulfur dioxide in this case. Table 7-42, identifies Hyperion's proposed control option, the rank of the control option, and the proposed emission limit.

Table 7-42 – Proposed Sulfur Dioxide BACT Control and Limit for Sulfur Recovery Plant

Unit	Description	Proposed Control	Rank	Proposed Limit
#42	Sulfur recovery plant's thermal oxidizer	Claus reactor, tail gas treater, and thermal oxidizer	#2	A combined 114.2 pounds per hour for the system

Based on DENR's review, there are at three facilities with equivalent or more stringent limitations than those proposed by Hyperion for the proposed controls. DENR reviewed each of these to verify the BACT emission limit.

A review of Arizona Department of Environmental Quality's technical review for the permit for the Arizona Clean Fuels Yuma Refinery issued on September 18, 2006, notes that the emission limit hydrogen sulfide is 0.089 pounds per hour, which represents 99.97% control (page 181).

A review of Louisiana Department of Environmental Quality's permit for Marathon Petroleum Company's Garyville Refinery issued on December 27, 2006, notes that the emission limit for sulfur dioxide, which also minimizes hydrogen sulfide emissions was 56.86 pounds per hour, which represents 99.95% control (page 11 and 15).

A review of New Mexico Environment Department's permit for Navajo Refining Company's Artesia Refinery notes that the emission limit for sulfur dioxide is 192 parts per million by volume, which represents 99.8% control (page 33).

DENR's review indicates that the Claus reactor, tail gas treater, and thermal oxidizer is the appropriate control technology choice for sulfur dioxide to represent BACT for the sulfur recovery plant. At first glance it appears that the Garyville Refinery has a lower sulfur dioxide emission limit when you compare the 56.86 pounds per hour limit to the limit Hyperion used for the sulfur recovery plant of 114.2 pounds per hour. As noted in the Garyville Refinery permit, the sulfur dioxide emission limit represents 99.95% control efficiency. The sulfur dioxide emission limit for Hyperion's sulfur recovery plant represents 99.97% control efficiency. Therefore, DENR determined that Hyperion's sulfur dioxide emission limit is more restrictive.

Since the other refineries have different emission limit units, DENR used the corresponding control efficiency noted in the permit for each refinery to determine if Hyperion's sulfur dioxide emission rate was more restrictive. Comparing the control efficiencies, DENR determined that Hyperion's sulfur dioxide emission limit was more restrictive. DENR agrees with the sulfur dioxide BACT emission limit identified in Table 7-42 for each thermal oxidizer associated with the sulfur recover plant.

DENR is also recommending a 0.056 pounds per long ton limit to ensure that each thermal oxidizer system is operated properly. The 114.2 pounds per hour limit was divided by the maximum sulfur loading of 2,040 long tons per hour to convert the emission limit to pounds per long ton sulfur. This limit will apply to each thermal oxidizer separately and not a combined limit.

DENR is requiring compliance based on a 3-hour average, excluding periods of startup, shutdown, and malfunctions and a 365-day rolling average, including periods of startup, shutdown, and malfunctions, using a continuous emission monitoring system.

7.1.2.4 Sulfur Dioxide BACT for IGCC Combustion Turbines

Hyperion's petroleum coke production design by itself is not sufficient to run the power plant at full capacity. Hyperion is proposing a "maximum coke design case" and "natural gas design case" to fire five combined cycle combustion turbines to generate electricity for Hyperion's refinery. Under the "maximum coke design case", the combustion turbines will be fired with syngas and pressure swing adsorption tail gas derived from petroleum coke and/or coal. Also under this scenario, additional petroleum coke or coal will be purchased to produce the additional fuel demand necessary for the power plant.

The "natural gas design case" will burn natural gas and pressure swing adsorption tail gas derived from the petroleum coke and/or coal. Instead of purchasing additional petroleum coke or coal to produce additional pressure swing adsorption tail gas, under the "natural gas design case", natural gas will be purchased to supplement the fuel demand for the power plant.

In both options, distillate oil will be used as a backup, which would generally occur during startup.

Hyperion identified in its application several options for BACT and identified which options were considered feasible or infeasible. Table 7-43 identifies the BACT options for the IGCC combustion turbines and if the options were considered feasible to install. DENR agreed with the first two steps of the BACT analysis.

Table 7-43 – Sulfur Dioxide Options and Feasibility for Combustion Turbines

Unit	Description	BACT Options	Feasible Options
#60 through #64	Combined cycle combustion turbines	Syngas – Fuel gas cleanup by chemical absorption	Yes
		Syngas – Fuel gas cleanup by physical absorption	Yes
		Syngas – Flue gas desulfurization	Yes
		Distillate oil – Ultra low sulfur fuel	Yes
		Natural gas – Pipeline-quality natural gas	Yes

In the application, Hyperion ranked the feasible control options based on estimated emission rates, which are displayed in Table 7-44.

Table 7-44 – Top Sulfur Dioxide BACT Control Options for Combustion Turbines

Unit	Description	Feasible Options	Estimated Emission Rates	Rank
#60 through #64	Combined cycle combustion turbines	Syngas and PSA tail gas – Fuel gas cleanup by physical absorption (Rectisol)	1 ppmv sulfur (0.0005 lbs/MMBtu [1])	#1
		Syngas and PSA tail gas – Fuel gas cleanup by physical absorption (Selexol)	10 ppmv sulfur (0.005 lbs/MMBtu [1])	#2
		Syngas and PSA tail gas – Fuel gas cleanup by chemical absorption	35 to 40 ppmv sulfur (0.02 lbs/MMBtu [1])	#3
		Syngas and PSA tail gas – Flue gas desulfurization	0.03 lbs/MMBtu [2]	#4
		Distillate oil – Ultra low sulfur fuel	15 ppmw sulfur (0.0015 lbs/MMBtus) [3]	#1
		Natural gas - Pipeline-quality natural gas	0.5 grains per 100 cubic foot (0.0014 lbs/MMBtus [4])	#1

Note: "ppmv" means parts per million by volume; "lbs/MMBtu" means pounds per million Btus; "ppmw" means parts per million by weight; and "PSA" means pressure swing adsorption
[1] – Based on the heat input of 320 million Btus per cubic foot of gas (primarily hydrogen);
[2] –Based on a correlation of heat inputs for refinery gas (1,255 MMBtus/cubic foot) to syngas (320 MMBtus/cubic foot).
[3] – Based on the heat input of 140,000 Btus per gallon; and
[4] – Based on the definition of pipeline natural gas in 40 CFR §72.2;

Table 7-45 identifies Hyperion's proposed control option, the rank of the control option, and the proposed emission limit.

Table 7-45 – Proposed Sulfur Dioxide BACT Control and Limit for Combustion Turbines

Unit	Description	Proposed Control	Rank	Proposed Limit
#60 through #64	Combined cycle combustion turbines	Fuel gas cleanup by physical absorption (Rectisol®)	#1	1 part per million by volume sulfur (syngas) [1]
				0.5 parts per million by volume sulfur (pressure swing adsorption tail gas) [1]
				1 part per million by volume sulfur (syngas and pressure swing adsorption tail gas) [2]
		Distillate oil – Ultra low sulfur fuel	#1	15 parts per million by weight sulfur or less
		Natural gas – Pipeline natural gas	#1	No proposed limit

[1] – Compliance based on a 24-hour rolling average, excluding periods of startup, shutdown, and malfunctions; and
[2] – Compliance based on a 365-day rolling average, including periods of startup, shutdown, and malfunctions.

The syngas sulfur cleanup by physical absorption occurs at the power island acid gas removal system (Unit #59) and is identified as Rectisol ® wash.

Based on DENR's review, there are at two facilities and one state rule with equivalent or more stringent limitations than those proposed by Hyperion for the proposed control. DENR reviewed each of these to verify the BACT emission limit.

A review of Kentucky Department of Environmental Protection permit to Cash Creek Generation facility issued on January 17, 2008, for the integrated gasification combined cycle system notes that the emission limit was 0.0158 pounds per million Btus for syngas and 0.0006 pounds per million Btus for natural gas (page 3).

A review of Illinois EPA's permit to Christian County Generation facility issued on June 5, 2007, for the integrated gasification combined cycle notes the emission rate of 0.016 pounds per million Btus for syngas and 0.001 pounds per million Btus for natural gas (page 28).

A review of California's South Coast Air Management District's Rule 431.1 – Sulfur Content of Gaseous Fuels notes a hydrogen sulfide limit of 40 parts per million volume (page 431.1-3).

DENR review indicates that fuel gas cleanup by physical absorption (Rectisol) is the appropriate control technology choice to represent BACT for the IGCC combustion turbines. DENR agrees that the emission limits proposed for the IGCC combustion turbines identified in Table 7-45, except for natural gas. Based on DENR's review, separate sulfur dioxide limits have been established for syngas and natural gas. Therefore, DENR is recommending a sulfur limit for natural gas of 9 parts per million by volume sulfur, which is based on the definition of pipeline-quality natural gas. DENR agrees with Hyperion's method of demonstrating as specified in Table 7-45.

7.1.2.5 Sulfur Dioxide BACT for IGCC Startup Burners

Hyperion is proposing a "maximum coke design case" and "natural gas design case" to fire five combined cycle combustion turbines to generate electricity for the Hyperion's refinery. Under the "maximum coke design case", the system will use eight gasifier startup burners fired with natural gas. In this case, only six will operated at one time with two gasifier startup burners are used as a backup. The "maximum natural gas design case", will use seven gasifier startup burners. In this case, only five will operate at one time and two are used as a backup.

Hyperion identified in its application one option for BACT. Table 7-46 identifies the BACT option for IGCC startup burners and if the option is considered feasible to install. DENR agreed with the first two steps of the BACT analysis.

Table 7-46 – Sulfur Dioxide Options and Feasibility for IGCC Startup Burners

Unit	Description	BACT Options	Feasible Options
#51 through #58	Gasifier startup burners	Good combustion practices	Yes

In the application, Hyperion did not rank the BACT options in this case since there is only one option. Since there is only one option, good combustion practice is the top sulfur dioxide control option for the IGCC startup burners.

Table 7-47, identifies Hyperion's proposed control option, the rank of the control option, and the proposed emission limit.

Table 7-47 – Proposed Sulfur Dioxide BACT Control and Limit for IGCC Startup Burners

Unit	Description	Proposed Control	Rank	Proposed Limit
#51 through #58	Gasifier startup burners	Good combustion practices	#1	Work practice standards for burning natural gas, no limit proposed

Based on DENR's review, there are at two facilities with equivalent or more stringent limitations than those proposed by Hyperion for the proposed control. DENR reviewed each of these to verify the BACT emission limit.

A review of Kentucky Department of Environmental Protection permit to Cash Creek Generation facility issued on January 17, 2008, for the integrated gasification combined cycle system notes that the emission limit was 0.006 pounds per million Btus (page 14).

A review of Illinois EPA's permit to Christian County Generation facility issued on June 5, 2007, for the integrated gasification combined cycle notes the emission rate of 0.006 pounds per million Btus (page 63).

DENR agrees that good combustion practices are the appropriate control technology choice to represent BACT for gasifier startup burners. Hyperion proposed a work practice standard as BACT that would be based on using pipeline-quality natural gas. DENR does not agree that work practice standards should be the proposed limit based on the numerical limits in the two permits review in this analysis. Therefore, DENR will establish a sulfur dioxide emission limit for each gasifier startup burner of 0.006 pounds per million Btu.

Compliance with the BACT sulfur dioxide limit shall be based on burning pipeline-quality natural gas.

7.1.2.6 Sulfur Dioxide BACT for Generators and Fire Pumps

Hyperion identified in its application several options for BACT and identified which options were considered feasible or infeasible. Table 7-48 identifies the BACT options reviewed for generators and fire pumps, and if the options were considered feasible to install. DENR agreed with the first two steps of the BACT analysis.

Table 7-48 – Sulfur Dioxide Options and Feasibility for Generators and Fire Pumps

Unit	Description	BACT Options	Feasible Options
#65 through #70	Emergency generators and fire pumps	Ultra low-sulfur diesel fuel	Yes
		Low-sulfur diesel fuel	Yes

Table 7-49 identifies the feasible options, the estimated sulfur content for each type of fuel, and the rank for each fuel type.

Table 7-49 – Top Sulfur Dioxide Control Options for Generators and Fire Pumps

Unit	Description	BACT Options	Control Efficiency	Rank
#65 through #70	Emergency generators and fire pumps	Ultra low-sulfur diesel fuel	15 parts per million by weight sulfur	#1
		Low-sulfur diesel fuel	500 parts per million by weight sulfur	#2

Hyperion chose the #1 ranked option. Table 7-50, identifies Hyperion's proposed control option, the rank of the control option, and the proposed emission limit.

Table 7-50 – Proposed Sulfur Dioxide BACT Control and Limit for Generators/Fire Pumps

Unit	Description	Proposed Control	Rank	Proposed Limit
#65 through #70	Emergency generators and fire pumps	Ultra low-sulfur diesel fuel	#1	15 part per million by weight sulfur

Based on DENR's review, there is one facility with equivalent or more stringent limitations than those proposed by Hyperion for the proposed controls. DENR reviewed each of these to verify the BACT emission limit.

A review of Arizona Department of Environmental Quality's technical review for the permit for the Arizona Clean Fuels Yuma Refinery issued on September 18, 2006, notes an emission limit of 15 parts per million by weight sulfur in the distillate oil (page 440).

DENR agrees with the BACT analysis. However, Hyperion analysis alludes that a 2007 model engine could be purchased which would have higher emission rates than those required for a 2008 model year engine or greater. Hyperion will be able to purchase a 2008 model engine or greater once the permit is issued. Therefore, DENR recommends the BACT be the New Source Performance Standard requirements and require 2008 or new model engine shall be purchased and operated.

7.1.2.7 Sulfur Dioxide BACT for Refinery and Gasification Flares

Due to the proposed control equipment, a BACT analysis for sulfur dioxide was conducted for the refinery flares. In addition, a BACT analysis was conducted for the gasification flare, which will be used for the safe disposal of off-specification syngas that is produced during unit startups, shutdowns and malfunctions and that cannot be routed to the combined cycle combustion turbines, the pressure swing adsorption unit, or to another gasifier.

Hyperion identified in its application several options for BACT and identified which options were considered feasible or infeasible. Table 7-51 identifies the BACT options reviewed for refinery flares and gasification flare, and if the options were considered feasible to install. DENR agreed with the first two steps of the BACT analysis.

Table 7-51 – Sulfur Dioxide Options and Feasibility for Refinery and Gasification Flares

Unit	Description	BACT Options	Feasible Options
#36 through #40 and #50	Refinery and gasification flares	Fuel gas cleanup by chemical absorption	Yes
		Fuel gas cleanup by physical absorption	Yes
		Flue gas desulfurization	Yes
		Good combustion practices and flare minimization plan	Yes

The BACT requirement for the refinery gas under the process heater discussion required the fuel gas to be cleaned by a chemical absorption or to be cleaned to 25 parts per million by volume sulfur. Even though fuel gas techniques are feasible to implement, this requirement is an inherent portion of the refinery process and is not a consideration specific to the operations of the flare.

The BACT requirement for the syngas under the gasification turbines discussion required the syngas to be cleaned by physical absorption or to be cleaned to 1 parts per million by volume sulfur. Even though fuel gas techniques are feasible to implement, this requirement is an inherent portion of the gasification and acid gas removal process and is not a consideration specific to the operations of the flare.

The last feasible option is good combustion practices and flare minimization plan. Table 7-52, identifies Hyperion's proposed control option, the rank of the control option, and the proposed emission limit.

Table 7-52 – Proposed Sulfur Dioxide BACT Control and Limit for Flares

Unit	Description	Proposed Control	Rank	Proposed Limit
#36 through #40 and #50	Refinery and gasification flares	Good combustion practices and flare minimization plan	#1	Work practice requirements and design requirements in 40 CFR §60.18, no proposed limit

Based on DENR's review, there is one facility and two state rules with an equivalent or more stringent limitation than those proposed by Hyperion for the proposed controls. DENR reviewed each of these to verify the BACT emission limit.

A review of California's South Coast Air Management District's Rule 1118 – Control of Emissions from Refinery Flares amended November 4, 2005, specifies a work practice and design requirement for the operations of the flares (pages 1118-5 through 1118-7). The rule does not specify a numerical limit for flares.

A review of California's Bay Area Air Quality Management District's Regulation 12 Rule 11 – Flare Monitoring at Petroleum Refineries and Regulation 12 Rule 12 – Flares at Petroleum Refineries, specifies a work practice and design requirement for the operations of the flares (12-12-3). The rule does not specify a numerical limit for flares.

A review of Arizona Department of Environmental Quality's permit for the Arizona Clean Fuels Yuma Refinery issued on September 18, 2006, specifies a work practice and design requirements for the operations of the flares (page 401 through 407).

DENR's review indicates that good combustion practices and a flare minimization plan is the appropriate control technology choice for sulfur dioxide to represent BACT for refinery and gasification flares. The operations of a flare are not conducive to conduct a performance test. Therefore, DENR agrees with Hyperion that a numerical sulfur dioxide emission limit is not feasible to implement.

7.1.2.8 Sulfur Dioxide BACT for Wastewater Treatment Plant

The technology chosen in Hyperion's BACT analysis for the wastewater treatment facility resulted in a BACT analysis for sulfur dioxide emissions. DENR is assuming the BACT analysis conducted for sulfur dioxide emissions from the process heaters would be the same for the wastewater treatment plant because sulfur dioxide emissions are generated from the sulfur content fuel being burned. Therefore, that BACT analysis for sulfur dioxide from process heaters will be used to represent BACT for the wastewater treatment plant.

7.1.2.9 Sulfur Dioxide BACT for Tank Farm Thermal Oxidizer

Hyperion conducted a BACT analysis for the Tank Farm for volatile organic compounds. DENR disagreed that a thermal oxidizer was not considered BACT for controlling most of the storage tanks. Due to the control technology recommended by DENR, DENR also conducted a BACT review for sulfur dioxide.

DENR is assuming the BACT analysis conducted for sulfur dioxide emissions from the process heaters would be the same for the wastewater treatment plant because sulfur dioxide emissions are generated from the sulfur content fuel being burned. Therefore, that BACT analysis for sulfur dioxide from process heaters will be used to represent BACT for the wastewater treatment plant.

7.1.3 BACT Analysis for Nitrogen Oxide

7.1.3.1 Nitrogen Oxide BACT for Process Heaters

In Hyperion's Nitrogen Oxide BACT analysis for the process heaters, Hyperion separated the BACT analysis into two categories: 1) large process heaters; and 2) small process heaters. The large process heaters have a maximum heat input greater than 70 million Btus per hour. The small process heaters have a maximum heat input of 70 million Btus per hour or less.

Hyperion identified in its application several options for BACT and identified which options were considered feasible or infeasible. Table 7-53 identifies the BACT options reviewed for small and large process heaters and if the options were considered feasible to install. DENR agreed with the first two steps of the BACT analysis.

Table 7-53 – Nitrogen Oxide Options and Feasibility for Process Heaters

Unit	Description	BACT Options	Feasible Options
#1 through #20	Large process heaters	Low-NOx and ultra Low-NOx burners	Yes
		Flue gas recirculation	Yes
		EMx ™	Yes
		Selective catalytic reduction	Yes
		Selective non-catalytic reduction	Yes
#21 through #30	Small process heaters	Low-NOx and ultra Low-NOx burners	Yes
		Flue gas recirculation	Yes
		EMx ™	Yes
		Selective catalytic reduction	Yes
		Selective non-catalytic reduction	Yes

In the application, Hyperion ranked the feasible control options based on the estimated emission rates, which are displayed in Table 7-54. DENR provided estimated control efficiencies based on EPA's *"Alternative Control Techniques Document – NOx Emissions from Process Heaters"*.

Table 7-54 – Top Nitrogen Oxide Control Options for Process Heaters

Unit	Description	Feasible Options	Estimated Emission Rates (Control Efficiency)	Rank
#1 through #20	Large process heaters	Low-NOx burners and selective catalytic reduction	< 0.006 pounds per million Btus (88%) [1]	#1
		Selective catalytic reduction	(75%) [1]	#2
		Ultra Low-NOx burners	< 0.025 pounds per million Btus (75%) [1]	
		Selective non-catalytic reduction	(60%) [1]	#3
		Low-NOx burners	0.05 pounds per million Btus (50%) [1]	#4
#21 through #30	Small process heaters	Low-NOx burners and selective catalytic reduction	< 0.006 pounds per million Btus (88%) [1]	#1
		Selective catalytic reduction	(75%) [1]	#2
		Ultra Low-NOx burners	< 0.025 pounds per million Btus (75%) [1]	
		Selective non-catalytic reduction	(60%) [1]	#3
		Low-NOx burners	0.05 pounds per million Btus (50%) [1]	#4

[1] – The control efficiencies were based on EPA's *"Alternative Control Techniques Document – NOx Emissions from Process Heaters"*.

Hyperion determined that the installation of selective catalytic reduction on the small process heaters was cost prohibitive at $30,000 per ton. Table 7-55 identifies Hyperion's proposed control option, the rank of the control option, and the proposed emission limit.

Table 7-55 – Proposed Nitrogen Oxide BACT Control and Limit for Process Heaters

Unit	Description	Proposed Control	Rank	Proposed Limit
#1 through #20	Large process heaters	Low-NOx burner and selective catalytic reduction	#1	0.006 pounds per million Btus [1]
#21 through #30	Small process heaters	Ultra low NOx burners	#2	0.025 pounds per million Btus [1]

[1] – Compliance is based on a 3-hour rolling average, excluding startups, shutdowns, and malfunctions. Compliance is based on a 365-day rolling average, including startups, shutdowns, and malfunctions.

Based on DENR's review, there are at two facilities and two state rules with equivalent or more stringent limitations than those proposed by Hyperion for the proposed controls. DENR reviewed each of these to verify the BACT emission limit.

A review of California's South Coast Air Management District's Rule 1109 – Emissions of Oxides of Nitrogen from Boilers and Process Heaters in Petroleum Refineries amended August 5, 1988, notes an emission limit for all process heaters of 0.03 pounds per million Btus (page 1109-3).

A review of California's Bay Area Air Quality Management District's Regulation 9 Rule 10 – Nitrogen Oxides and Carbon Monoxide from Boilers, Steam Generators and Process Heaters in Petroleum Refineries, notes an emission limit for all process heaters of 0.033 pounds per million Buts (page 9-10-4).

A review of Arizona Department of Environmental Quality's permit for the Arizona Clean Fuels Yuma Refinery issued on September 18, 2006, notes that the emission limit initially for the large process heaters is 0.0125 pounds per million Btus and is lowered to 0.006 pounds per million Btus after 18 months of operation unless a request is submitted to Arizona requesting the lower limit is not feasible and the request is approved (identified through the permit but starting on page 22). For the small heaters, Arizona's permit noted emission limits in the range from 0.025 to 0.034 pounds per million Btus (identified throughout the permit but starting on page 65).

A review of South Coast Air Quality Management District's permit to Ceneco Refining Company for its Santa Fe Springs Refinery issued on November 17, 2000, notes that an a selective catalytic reduction system and an emission limit of 0.006 pounds per million Btus was required for a heater with a heat input of 50 million Btus per hour (page 151 of the pdf file). As noted in Lakeland Processing Company's Audit document revised March 2005 (page 9), the refinery has been in existence since the 1930's. Powerine Oil Company operated from 1936 until 1984 when the refinery went into bankruptcy in 1984 and ceased refinery operations. The refinery emerged from bankruptcy in 1986 and resumed refining activities until 1995. Cenco Refining Company purchased the refinery in 1998 with plans to resume refining. In 2002, Cenco Refining Company decided not to reopen the refinery but instead decided to redevelop the site for other uses such as a non-hazardous liquid waste treatment facility.

DENR agrees that the Low-NOx burner with a selective catalytic reduction system is BACT for the large process heaters and the ultra low-NOx burner is BACT for the small process heater. In DENR's review, the BACT emission limit for nitrogen oxide ranged from 0.006 to 0.033 pounds per million Btus for process heaters. The first time the process heaters are divided into "large" and "small" categories was with the permit issued in Arizona. DENR agrees with basing the BACT emission limit for nitrogen oxide on the size of the unit based on what was considered economically feasible for the different size units in the Hyperion application.

Hyperion is proposing compliance be demonstrated on a 3-hour rolling average, except during periods of startup, shutdown, and malfunctions and on a 365-day rolling average, including periods of startup, shutdown, and malfunctions. DENR agrees with the Hyperion's proposed emission limits in Table 7-55 and the method of demonstrating compliance.

7.1.3.2 Nitrogen Oxide BACT for Catalyst Regenerators

Hyperion identified in its application several options for BACT and identified which options were considered feasible or infeasible. Table 7-56 identifies the BACT options reviewed for the catalyst regenerators and if the options were considered feasible to install. DENR agreed with the first two steps of the BACT analysis.

Table 7-56 – Nitrogen Oxide Options and Feasibility for Catalyst Regenerators

Unit	Description	BACT Options	Feasible Options
#31	Number one platformer catalyst regenerator	Work practice standards	Yes
		Selective catalytic reduction	No
		Selective non-catalytic reduction	No
#32	Number two platformer catalyst regenerator	Work practice standards	Yes
		Selective catalytic reduction	No
		Selective non-catalytic reduction	No
#33	Oleflex catalyst regenerator	Work practice standards	Yes
		Selective catalytic reduction	No
		Selective non-catalytic reduction	No

Hyperion indicated in the application that the size of the catalyst regenerators and operating temperature result in the selective catalytic reduction and selective non-catalytic reduction controls technically infeasible. Since there is only one option, work practice standard is the top nitrogen oxide control option for catalyst regenerators. Table 7-57, identifies Hyperion's proposed control option, the rank of the control option, and the proposed emission limit.

Table 7-57 – Proposed Nitrogen Oxide BACT Control and Limit for Catalyst Regenerators

Unit	Description	Proposed Control	Rank	Proposed Limit
#31	Number one platformer catalyst regenerator	Work practice standards	#1	0.1 pounds per hour
#32	Number two platformer catalyst regenerator	Work practice standards	#1	0.1 pounds per hour
#33	Oleflex catalyst regenerator	Work practice standards	#1	0.02 pounds per hour

Based on DENR's review, there is one facility with equivalent or more stringent limitations than those proposed by Hyperion for the proposed controls. DENR reviewed each of these to verify the BACT emission limit.

A review of Arizona Department of Environmental Quality's permit for the Arizona Clean Fuels Yuma Refinery issued on September 18, 2006, establishes an emission limit 0.82 pounds per million Btus for nitrogen oxide (page 82).

DENR review indicates that the work practice standard is the appropriate control technology choice to represent BACT for the catalyst regenerators. DENR agrees that the emission limits proposed for catalyst regenerators identified in Table 7-57.

Demonstrating compliance with the BACT emission limit for nitrogen oxide was not specified by Hyperion for the catalyst regenerators. DENR is proposing demonstrating compliance by a 3-hour average based on a stack performance test.

The BACT emission limit for nitrogen oxide is not applicable during periods of startup, shutdown, or malfunctions. The BACT nitrogen oxide emission limit during these occurrences will be discussed later.

7.1.3.3 Nitrogen Oxide BACT for Sulfur Recovery Plant

The air emissions from the sulfur recovery plant will be controlled by six thermal oxidizers (Unit #42a, #42b, #42c, #42d, and #42e). Hyperion is proposing to operate a maximum of four thermal oxidizers at one time. As such, a minimum of two thermal oxidizers are being installed as a backup.

Hyperion identified in its application several options for BACT and identified which options were considered feasible or infeasible. Table 7-58 identifies the BACT options reviewed for the sulfur recovery plant and if the options were considered feasible to install. DENR agreed with the first two steps of the BACT analysis.

Table 7-58 – Nitrogen Oxide Options and Feasibility for Sulfur Recovery Plant

Unit	Description	BACT Options	Feasible Options
#42	Sulfur recovery plant's thermal oxidizer	Low-NOx	Yes
		Flue gas recirculation	No
		EMx ™	No
		Selective catalytic reduction	No
		Selective non-catalytic reduction	No

Hyperion identified in the application that the flue gas recirculation system would unacceptably lessen the effect of the thermal oxidizer by reducing the flame temperature and is therefore, technically infeasible. Hyperion identified the EMx™, selective catalytic reduction, and selective non-catalytic reduction as technically infeasible because the exhaust gases would contain in some cases high levels of sulfur dioxide would foul and poison the catalyst in the EMx™ and selective catalytic reduction systems and all three would lessen the reliability of the thermal oxidizer.

Since there is only one option, Low-NOx burner is the top nitrogen oxide control option for the sulfur recovery plant. Table 7-59, identifies Hyperion's proposed control option, the rank of the control option, and the proposed emission limit.

Table 7-59 – Proposed Nitrogen Oxide BACT Control and Limit for Sulfur Recovery Plant

Unit	Description	Proposed Control	Rank	Proposed Limit
#42	Sulfur recovery plant's thermal oxidizer	Low-NOx burners	#1	0.068 pounds per million Btus [1]

[1] – Compliance is based on a 3-hour rolling average.

Based on DENR's review, there are two facilities with equivalent or more stringent limitations than those proposed by Hyperion for the proposed controls. DENR reviewed each of these to verify the BACT emission limit.

A review of Arizona Department of Environmental Quality's permit for the Arizona Clean Fuels Yuma Refinery issued on September 18, 2006, establishes an emission limit 0.06 pounds per million Btus for nitrogen oxide (page 208).

A review of Louisiana Department of Environmental Quality permit to Conoco Phillips Company's Lake Charles Refinery issued on May 19, 2006, indicates that the emission limit is 0.18 pounds per million Btus and based on a combustion device approximately 40 million Btus per hour, which equates to 7.5 pounds per hour (page 19).

DENR agrees that the use of the Low-NOx burners represents the best control option of the BACT analysis. However, DENR disagrees with the emission limit to represent the use of Low-NOx burners. DENR's review determined that the BACT emission limit for nitrogen oxide ranged from 0.06 to 0.18 pounds per million Btus for the sulfur recovery plant. DENR recommends the emission limit of 0.06 pounds per million Btus to represent the limit portion of BACT.

DENR is requiring compliance based on a 3-hour average, excluding periods of startup, shutdown, and malfunctions and a 365-day rolling average, including periods of startup, shutdown, and malfunctions, using a continuous emission monitoring system.

7.1.3.4 Nitrogen Oxide BACT for IGCC Combustion Turbines

Hyperion's petroleum coke production design by itself is not sufficient to run the power plant at full capacity. Hyperion is proposing a "maximum coke design case" and "natural gas design case" to fire five combined cycle combustion turbines to generate electricity for Hyperion's refinery. Under the "maximum coke design case", the combustion turbines will be fired with syngas and pressure swing adsorption tail gas derived from petroleum coke and/or coal. Also under this scenario, additional petroleum coke or coal will be purchased to produce the additional fuel demand necessary for the power plant.

The "natural gas design case" will burn natural gas and pressure swing adsorption tail gas derived from the petroleum coke and/or coal. Instead of purchasing additional petroleum coke or coal to produce additional pressure swing adsorption tail gas, under the "natural gas design case", natural gas will be purchased to supplement the fuel demand for the power plant.

Hyperion identified in its application several options for BACT and identified which options were considered feasible or infeasible. Table 7-60 identifies the BACT options reviewed for the IGCC combustion turbines and if the options were considered feasible to install. DENR agreed with the first two steps of the BACT analysis.

Table 7-60 – Nitrogen Oxide Options and Feasibility for Combustion Turbines

Unit	Description	BACT Options	Feasible Options
#60 through #64	Combined cycle combustion turbines	Dry Low-NOx (combustion turbine)	Yes
		Low-NOx burners (duct burners)	Yes
		Diluent injection (combustion turbines	Yes
		EMx ™	No
		Selective catalytic reduction	Yes
		Selective non-catalytic reduction	No

Hyperion identified in the application that the EMx™ system has not been demonstrated to operate successfully with the size of the units being proposed by Hyperion. Hyperion also indicated that the selective non-catalytic reduction was technically infeasible because there were no flue gas locations that would meet the requisite temperature and residence time characteristics.

The feasible control options were ranked based on estimated control efficiencies by DENR, which are displayed in Table 7-61.

Table 7-61 – Top Nitrogen Oxide BACT Control Options for Combustion Turbines

Unit	Description	Feasible Options	Control Efficiency	Rank
#60 through #64	Combined cycle combustion turbines	Selective catalytic reduction	(65 to 90%) [1]	#1
		Diluent injection (combustion turbine)	(60%) [1]	#2
		Dry Low-NOx burners (combustion)		#3
		Low-NOx burners (duct burner)	(50%) [2]	#4

[1] – The efficiencies were based on EPA's AP-42 emission factors for stationary gas turbines; and
[2] –The efficiencies were based on EPA's Alternative Control Techniques Document – NOx Emissions from Process Heaters.

Table 7-62, identifies Hyperion's proposed control option, the rank of the control option, and the proposed emission limit.

Table 7-62 – Proposed Nitrogen Oxide BACT Control and Limit for Combustion Turbines

Unit	Description	Proposed Control	Rank	Proposed Limit
#60 through #64	Combined cycle combustion turbines (syngas, pressure swing adsorption tail gas, and diesel fuel)	Low NOx duct burner, diluent injection, and selective catalytic reduction	#1	3 parts per million by volume nitrogen oxide (syngas/pressure swing adsorption tail gas) [1]; 6 parts per million by volume nitrogen oxide (distillate oil) [1]; and 3 parts per million by volume nitrogen oxide (syngas, pressure swing adsorption tail gas, and/or distillate oil) [2]
	Combined cycle combustion turbines (pressure swing adsorption tail gas, natural gas, and diesel fuel)	Low NOx duct burner, dry Low-NOx burner (combustion), and selective catalytic reduction	#1	2 parts per million by volume nitrogen oxide (pressure swing adsorption tail gas/natural gas) [1]; 6 parts per million by volume nitrogen oxide (distillate oil) [1]; and 2 parts per million by volume nitrogen oxide (pressure swing adsorption tail gas, natural gas, and/or distillate oil) [2]

[1] – Corrected to 15% oxygen and compliance is based on a 3-hour rolling average, excluding periods of startup, shutdown, or malfunctions; and
[2] – Corrected to 15% oxygen and compliance is based on a 365-day rolling average, including periods of startup, shutdown, or malfunctions;

Based on DENR's review, there are two facilities and two state rules with equivalent or more stringent limitations than those proposed by Hyperion for the proposed controls. DENR reviewed each of these to verify the BACT emission limit.

A review of California's South Coast Air Management District's Rule 1109 – Emissions of Oxides of Nitrogen from Boilers and Process Heaters in Petroleum Refineries amended August 5, 1988, notes an emission limit for all process heaters of 0.03 pounds per million Btus, which is approximately 8 parts per million corrected to 15 percent oxygen (page 1109-3).

A review of California's Bay Area Air Quality Management District's Regulation 9 Rule 10 – Nitrogen Oxides and Carbon Monoxide from Boilers, Steam Generators and Process Heaters in Petroleum Refineries, notes an emission limit for all process heaters of 0.033 pounds per million Buts, which is approximately 9 parts per million corrected to 15 percent oxygen (page 9-10-4).

A review of Kentucky Department of Environmental Protection permit to Cash Creek Generation facility issued on January 17, 2008, for the integrated gasification combined cycle system notes that the emission limit was 0.0246 to 0.0331 pounds per million Btus, which equates to approximately 7 to 9 parts per million corrected to 15 percent oxygen (page 3).

A review of Illinois EPA's permit to Christian County Generation facility issued on June 5, 2007, for the integrated gasification combined cycle notes the emission rate of 0.025 to 0.033 pounds per million Btus, which equates to approximately 7 to 9 parts per million corrected to 15 percent oxygen (page 28).

DENR agrees that the use of the Low-NOx duct burners, diluent injection, and selective catalytic reduction represents the best control option of the BACT analysis for Hyperion's petroleum coke/coal option, and Low-NOx duct burners, dry Low-NOx burner (combustion), and selective catalytic reduction represents the best control option of the BACT analysis for Hyperion's natural gas option. DENR also agrees with the emission limit and compliance demonstrations established in Table 7-62.

7.1.3.5 Nitrogen Oxide BACT for IGCC Startup Burners

Hyperion is proposing a "maximum coke design case" and "natural gas design case" to fire five combined cycle combustion turbines to generate electricity for the Hyperion's refinery. Under the "maximum coke design case", the system will use eight gasifier startup burners fired with natural gas. In this case, only six will operated at one time with two gasifier startup burners are used as a backup. The "maximum natural gas design case", will use seven gasifier startup burners. In this case, only five will operate at one time and two are used as a backup.

Hyperion identified in its application one option for BACT. Table 7-63 identifies the BACT option for IGCC startup burners and if the option is considered feasible to install. DENR agreed with the first two steps of the BACT analysis.

Table 7-63 – Nitrogen Oxide Options and Feasibility for IGCC Startup Burners

Unit	Description	BACT Options	Feasible Options
#51 through #58	Gasifier startup burners	Low-NOx burners (duct burners)	Yes
		Flue gas recirculation	No
		EMx ™	No
		Selective catalytic reduction	No
		Selective non-catalytic reduction	No
		Good combustion practices	Yes

Hyperion identified in the application that the flue gas recirculation, EMx™, selective catalyst reduction, and selective non-catalytic reduction systems were not technically feasible because of the sporadic operating times of the units and stable, minimum temperatures, needed for the systems. In the application, Hyperion combined the remaining two options as BACT for nitrogen oxide.

Table 7-64, identifies Hyperion's proposed control option, the rank of the control option, and the proposed emission limit.

Table 7-64 – Proposed Nitrogen Oxide BACT Control and Limit for IGCC Startup Burners

Unit	Description	Proposed Control	Rank	Proposed Limit
#51 through #58	Gasifier startup burners	Low-NOx burners (duct burners) and good combustion practices	#1	Use of Low-NOx burners, no limit proposed

Based on DENR's review, there are two facilities with equivalent or more stringent limitations than those proposed by Hyperion for the proposed controls. DENR reviewed each of these to verify the BACT emission limit.

A review of Kentucky Department of Environmental Protection permit to Cash Creek Generation facility issued on January 17, 2008, for the integrated gasification combined cycle system notes that the emission limit was 0.036 pounds per million Btus (page 14). This emission limit is for a boiler, which uses indirect heat. The emission limit would not be representative of a startup burner that uses direct heat.

A review of Illinois EPA's permit to Christian County Generation facility issued on June 5, 2007, for the integrated gasification combined cycle notes the emission rate of 0.036 pounds per million Btus (page 63). This emission limit is for a boiler, which uses indirect heat. The emission limit would not be representative of a startup burner that uses direct heat. .

DENR agrees that Low-NOx burners are the appropriate control technology choice to represent BACT for gasifier startup burners. Hyperion did not propose a BACT emission limit for nitrogen oxide. In the application, Hyperion describes the amount of time the gasifier startup burners would operate. In each scenario the gasifier startup burners would operate equal to or more than eight hours at a time. A performance test could be conducted during this time period, which would not be due to startup, shutdown, or malfunction of the gasifier startup burner. DENR will establish a nitrogen oxide emission limit for each gasifier startup burner. DENR is proposing a BACT emission limit for nitrogen oxide of 0.07 pounds per million Btu, excluding startups, shutdowns, and malfunctions of the gasifier startup burner. The proposed limit is based on the emission rates used in the modeling and/or calculations.

Compliance with the BACT emission limit for nitrogen oxide shall be based on an average of three test runs based on a performance test. The BACT emission limit for nitrogen oxide is not applicable during periods of startup, shutdown, or malfunctions. The BACT emission limit for nitrogen oxide during these occurrences will be discussed later.

7.1.3.6 Nitrogen Oxide BACT for Generators and Fire Pumps

In the case of internal combustion engines such as generators and fire pumps, standards such as in 40 CFR Part 60, Subpart IIII have been established combining nitrogen oxides and non-methane hydrocarbons or volatile organic compounds. Therefore the following section will evaluate the combination of the two pollutants.

Hyperion identified in its application several options for BACT and identified which options were considered feasible or infeasible. Table 7-65 identifies the BACT options reviewed for generators and fire pumps, and if the options were considered feasible to install. DENR agreed with the first two steps of the BACT analysis.

Table 7-65 – NOx and VOC Options and Feasibility for Generators and Fire Pumps

Unit	Description	BACT Options	Feasible Options
#65 through #70	Emergency generators and fire pumps	NOx adsorb technology in conjunction with catalyzed diesel particulate filters	Yes
		SCR used in conjunction with oxidation catalyst	Yes
		Injection timing retard and exhaust gas recirculation	Yes

Table 7-66 identifies the feasible options, the estimated control efficiency by DENR, and the rank for each feasible option.

Table 7-66 – Top NOx and VOC Control Options for Generators and Fire Pumps

Unit	Description	BACT Options	Control Efficiency	Rank
#65 through #70	Emergency generators and fire pumps	NOx adsorb technology in conjunction with catalyzed diesel particulate filters	90% [1]	#1
		SCR used in conjunction with oxidation catalyst	80% [1]	#2
		Injection timing retard and exhaust gas recirculation	50 to 90% [2]	#3

[1] – The emission estimates were derived from the federal register notice of the proposed rules for New Source Performance Standard Subpart IIII (Vol. 71, No. 112 / Monday June 12, 2006); and
[2] –Memorandum from Tanya Parise. Alpha Gamma Technologies, Incorporated to Jaime Pagan, EPA Energy Strategies Group, dated December 18, 2007, Cost Impacts and Emission Reductions Associated with Final NSPS for Stationary SI ICE and NESHAP for Stationary RICE (page 17).

Hyperion identified in the application that based on the size of the unit, low emission rates, and they only operate intermittently, they propose option #3. Table 7-67, identifies Hyperion's proposed control option, the rank of the control option, and the proposed emission limit.

Table 7-67 – Proposed NOx and VOC BACT Control and Limit for Generators/Fire Pumps

Unit	Description	Proposed Control	Rank	Proposed Limit
#65 through #70	Emergency generators and fire pumps	Injection timing retard and exhaust gas recirculation	#3	New Source Performance Standard Subpart IIII requirement – 6.4 grams per kilowatt -hour

Based on DENR's review, there is one facility with equivalent or more stringent limitations than those proposed by Hyperion for the proposed controls. DENR reviewed each of these to verify the BACT emission limit.

A review of Arizona Department of Environmental Quality's technical review for the permit for the Arizona Clean Fuels Yuma Refinery issued on September 18, 2006, notes that the emission limit was 6.4 grams per kilowatt hour for similar size generators (page 441).

DENR agrees with the BACT analysis. However, Hyperion analysis alludes that a 2007 model engine could be purchased which would have higher emission rates than those required for a 2008 model year engine or greater. Hyperion will be able to purchase a 2008 model engine or greater once the permit is issued. Therefore, DENR recommends the BACT be the New Source Performance Standard requirements and require 2008 or new model engine shall be purchased and operated.

7.1.3.7 Nitrogen Oxide BACT for Refinery and Gasification Flares

Due to the proposed control equipment, a BACT analysis for nitrogen oxide was conducted for the refinery flares. In addition, a BACT analysis was conducted for the gasification flare, which will be used for the safe disposal of off-specification syngas that is produced during unit startups, shutdowns and malfunctions and that cannot be routed to the combined cycle combustion turbines, the pressure swing adsorption unit, or to another gasifier.

Hyperion identified in its application several options for BACT and identified which options were considered feasible or infeasible. Table 7-68 identifies the BACT options reviewed for refinery flares and gasification flare, and if the options were considered feasible to install. DENR agreed with the first two steps of the BACT analysis.

Table 7-68 – Nitrogen Oxide Options and Feasibility for Refinery and Gasification Flares

Unit	Description	BACT Options	Feasible Options
#36 through #40 and #50	Refinery and gasification flares	Low-NOx and Ultra Low-NOx burners	No
		Flue gas recirculation	No
		EMx ™	No
		Selective catalytic reduction	No
		Selective non-catalytic reduction	No
		Good combustion practices and flare minimization plan	Yes

In the application, Hyperion states that the inherent design of the emergency flares with wide variety of operational conditions, open flame on a tall stack do not allow for the use of Low-NOx burners or add-on control devices. That leaves only one feasible option, which is good combustion practices and a flare minimization plan. Table 7-69, identifies Hyperion's proposed control option, the rank of the control option, and the proposed emission limit.

Table 7-69 – Proposed Nitrogen Oxide BACT Control and Limit for Flares

Unit	Description	Proposed Control	Rank	Proposed Limit
#36 through #40 and #50	Refinery and gasification flares	Good combustion practices and flare minimization plan	#1	Work practice requirements and design requirements in 40 CFR §60.18, no proposed limit

Based on DENR's review, there is one facility and two state rules with an equivalent or more stringent limitation than those proposed by Hyperion for the proposed controls. DENR reviewed each of these to verify the BACT emission limit.

A review of California's South Coast Air Management District's Rule 1118 – Control of Emissions from Refinery Flares amended November 4, 2005, specifies a work practice and design requirement for the operations of the flares (pages 1118-5 through 1118-7). The rule does not specify a numerical limit for flares.

A review of California's Bay Area Air Quality Management District's Regulation 12 Rule 11 – Flare Monitoring at Petroleum Refineries and Regulation 12 Rule 12 – Flares at Petroleum Refineries, specifies a work practice and design requirement for the operations of the flares (12-12-3). The rule does not specify a numerical limit for flares.

A review of Arizona Department of Environmental Quality's permit for the Arizona Clean Fuels Yuma Refinery issued on September 18, 2006, specifies a work practice and design requirements for the operations of the flares (page 401 through 407).

DENR's review indicates that good combustion practices and a flare minimization plan is the appropriate control technology choice for nitrogen oxide to represent BACT for refinery and gasification flares. The operations of a flare are not conducive to conduct a performance test. Therefore, DENR agrees with Hyperion that a numerical nitrogen oxide emission limit is not feasible to implement.

7.1.3.8 Nitrogen Oxide BACT for Wastewater Treatment Plant

The technology chosen in Hyperion's BACT analysis for the wastewater treatment plant resulted in a BACT analysis for nitrogen oxide emissions. Hyperion identified in its application several options for BACT and identified which options were considered feasible or infeasible. Table 7-70 identifies the BACT options reviewed for the wastewater treatment facility and if the options were considered feasible to install. DENR agreed with the first two steps of the BACT analysis.

Table 7-70 – Nitrogen Oxide Options and Feasibility for Wastewater Treatment Plant

Unit	Description	BACT Options	Feasible Options
#45a	Wastewater treatment's catalytic oxidizer	Selective catalytic reduction	Yes
		No controls	No

The “no control” option was ranked #1 because there would be no nitrogen oxide emissions if the thermal oxidizer was not installed to control volatile organic compound emissions from the wastewater treatment plant. The no control options would not be environmental beneficial since controlling the volatile organic compounds emissions out weighs the increase in nitrogen oxide emissions generated from the thermal oxidizer. Therefore, the no control option was considered an infeasible option.

That leaves only one feasible option, which is selective catalytic reduction. Table 7-71, identifies Hyperion’s proposed control option, the rank of the control option, and the proposed emission limit.

Table 7-71 – Proposed Nitrogen Oxide BACT Control and Limit for Wastewater Treatment

Unit	Description	Proposed Control	Rank	Proposed Limit
#45a	Wastewater treatment’s catalytic oxidation	Selective catalytic reduction	#1	5.0 pounds per hour

Based on DENR’s review, there is no facility with equivalent or more stringent limitations than those proposed by Hyperion for the proposed controls. For example, a review of Arizona Department of Environmental Quality’s permit for the Arizona Clean Fuels Yuma Refinery issued on September 18, 2006, does not establish an emission limit for nitrogen oxide (page 346 through 357).

DENR’s review did not find a nitrogen oxide emission limit for a thermal oxidizer controlling air emissions from a wastewater treatment plant at a refinery. DENR agrees with the nitrogen oxide limit proposed by Hyperion.

DENR is requiring compliance based on a 3-hour average, excluding periods of startup, shutdown, and malfunctions and a 365-day rolling average, including periods of startup, shutdown, and malfunctions, using a continuous emission monitoring system.

7.1.3.9 Nitrogen Oxide BACT for Tank Farm Thermal Oxidizer

Hyperion conducted a BACT analysis for the Tank Farm for volatile organic compounds. DENR disagreed that a thermal oxidizer was not considered BACT for controlling most of the storage tanks. Due to the control technology recommended by DENR, DENR also conducted a BACT review for nitrogen oxide.

DENR based its review on Hyperion’s BACT analysis for the thermal oxidizers for the sulfur recovery plant, which resulted in the use of Low-NOx burners. Based on DENR’s review, there is one facility with equivalent or more stringent limitations than those proposed by Hyperion for the proposed controls.

A review of Arizona Department of Environmental Quality’s permit for the Arizona Clean Fuels Yuma Refinery issued on September 18, 2006, establishes an emission limit 0.04 pounds per million Btus for nitrogen oxide (page 266).

The BACT emission limit for nitrogen oxide is not applicable during periods of startup, shutdown, or malfunctions. The BACT nitrogen oxide emission limit during these occurrences will be discussed later.

7.1.4 BACT Analysis for Ozone (Measured as VOCs)

7.1.4.1 VOC BACT for Process Heaters

Hyperion identified in its application several options for BACT and identified which options were considered feasible or infeasible. Table 7-72 identifies the BACT options reviewed for small and large process heaters and if the options were considered feasible to install. DENR agreed with the first two steps of the BACT analysis.

Table 7-72 – VOC Options and Feasibility for Process Heaters

Unit	Description	BACT Options	Feasible Options
#1 through #30	Process heaters	Good combustion practices	Yes

In the application, Hyperion did not rank the BACT options in this case since there is only one option. Since there is only one option, good combustion practice is the top volatile organic compound control option for process heaters. Table 7-73, identifies Hyperion's proposed control option, the rank of the control option, and the proposed emission limit.

Table 7-73 – Proposed VOC BACT Control and Limit for Process Heaters

Unit	Description	Proposed Control	Rank	Proposed Limit
#1 through #30	Process heaters	Good combustion practices	#1	Use carbon monoxide limit as surrogate

Based on DENR's review, there are four facilities with equivalent or more stringent limitations than those proposed by Hyperion for good combustion practices. DENR reviewed each of these to verify the BACT emission limit.

A review of Texas Commission on Environmental Quality's technical review for the permit to Exxon Corporation's Exxon Bay Refinery issued on May 5, 1999, notes that the project was not required to conduct a PSD review for volatile organic compounds (page 3). The RBLC data indicates that the emission rate for the heaters at this refinery varies between 0.0013 to 0.006 pounds per million Btus.

A review of Texas Commission on Environmental Quality's technical review of the PSD permit for Fina Oil & Chemical Company's Port Arthur Refinery issued September 8, 1998, notes that the volatile organic compound emission limits were based on the lowest achievable emission rate, which is a requirement of a non-attainment area and not an attainment area (page 4). The RBLC data indicates that the emission rate for the heaters at this refinery varies between 0.001 to

0.003 pounds per million Btus. The majority of the heaters have an emission rate of approximately 0.003 pounds per million Btus

A review of Arizona Department of Environmental Quality's technical review for the permit for the Arizona Clean Fuels Yuma Refinery issued on September 18, 2006, notes that the emission limit for carbon monoxide would be used as a surrogate for volatile organic compounds (page 172 to 173).

A review of Louisiana Department of Environmental Quality's permit for Marathon Petroleum Company's Garyville Refinery issued December 27, 2006, notes that the emission limit for volatile organic compounds is 0.0015 pounds per million Btus (page 5).

DENR agrees that good combustion practices are the appropriate control technology choice to represent BACT for volatile organic compound emissions from the process heaters. However, DENR disagrees that using the BACT emission limit for carbon monoxide is the correct BACT emission limit proposed for good combustion practices. Hyperion also proposed good combustion practices for particulate matter and proposed an emission limit and not a different pollutant as a surrogate. Therefore, DENR believes in this instance that a volatile organic compound limit should be established.

In DENR's review, the BACT emission limit for volatile organic compounds ranged from 0.001 to 0.006 pounds per million Btus for process heaters. DENR is proposing a BACT emission limit for volatile organic compound of 0.0015 pounds per million Btus determined as carbon. DENR is proposing compliance be determined using a 3-hour average based on stack performance tests.

7.1.4.2 VOC BACT for Catalyst Regenerators

Hyperion did not identify emission estimates for volatile organic compounds for the catalyst regenerators. DENR was unable to locate an emission rate for volatile organic compounds, therefore, DENR agrees that the emission of volatile organic compounds are not generated or are negligible and do not require a BACT analysis.

7.1.4.3 VOC BACT for Sulfur Recovery Plant

The air emissions from the sulfur recovery plant will be controlled by six thermal oxidizers (Unit #42a, #42b, #42c, #42d, and #42e). Hyperion is proposing to operate a maximum of four thermal oxidizers at one time. As such a minimum of two thermal oxidizers are being installed as a backup.

Hyperion identified in its application several options for BACT and identified which options were considered feasible or infeasible. Table 7-74 identifies the BACT options reviewed for the sulfur recovery plant and if the options were considered feasible to install. DENR agreed with the first two steps of the BACT analysis.

Table 7-74 – VOC Options and Feasibility for Sulfur Recovery Plant

Unit	Description	BACT Options	Feasible Options
#42	Sulfur recovery plant's thermal oxidizer	Good combustion practices	Yes

Since there is only one option, good combustion practice is the top volatile organic compound control option for the sulfur recovery plant. Table 7-75, identifies Hyperion's proposed control option, the rank of the control option, and the proposed emission limit.

Table 7-75 – Proposed VOC BACT Control and Limit for Sulfur Recovery Plant

Unit	Description	Proposed Control	Rank	Proposed Limit
#42	Sulfur recovery plant's thermal oxidizer	Good combustion practices	#1	Use hydrogen sulfide limit as surrogate

Based on DENR's review, there is no facility with equivalent or more stringent limitations than those proposed by Hyperion for good combustion practices. For example, a review of Arizona Department of Environmental Quality's permit for the Arizona Clean Fuels Yuma Refinery issued on September 18, 2006, does not establish an emission limit for volatile organic compounds (page 208).

DENR agrees that good combustion practices are the appropriate control technology choice to represent BACT for the sulfur recovery plant's thermal oxidizer. However, DENR disagrees that the emission limit proposed for good combustion practices represents the limit portion of BACT. Hyperion also proposed good combustion practices for particulate matter and proposed an emission limit and not a different pollutant as a surrogate. Therefore, DENR believes in this instance that a volatile organic compound limit should be established. DENR review indicates that the volatile organic compound emission limit should be 0.005 pounds per million Btus determined as carbon. The proposed limit is based on the emission rates used in the modeling and/or calculations. Demonstrating compliance with the BACT emission limit for volatile organic compounds will be demonstrated by a 3-hour average based on a stack performance test.

The BACT emission limit for volatile organic compounds is not applicable during periods of startup, shutdown, or malfunctions. The BACT volatile organic compound emission limit during these occurrences will be discussed later.

7.1.4.4 VOC BACT for IGCC Combustion Turbines

Hyperion's petroleum coke production design by itself is not sufficient to run the power plant at full capacity. Hyperion is proposing a "maximum coke design case" and "natural gas design case" to fire five combined cycle combustion turbines to generate electricity for Hyperion's refinery. Under the "maximum coke design case", the combustion turbines will be fired with syngas and pressure swing adsorption tail gas derived from petroleum coke and/or coal. Also under this scenario, additional petroleum coke or coal will be purchased to produce the additional fuel demand necessary for the power plant.

The “natural gas design case” will burn natural gas and pressure swing adsorption tail gas derived from the petroleum coke and/or coal. Instead of purchasing additional petroleum coke or coal to produce additional pressure swing adsorption tail gas, under the “natural gas design case”, natural gas will be purchased to supplement the fuel demand for the power plant.

Hyperion identified in its application several options for BACT and identified which options were considered feasible or infeasible. Table 7-76 identifies the BACT options reviewed for the IGCC combustion turbines and if the options were considered feasible to install. DENR agreed with the first two steps of the BACT analysis.

Table 7-76 – VOC Options and Feasibility for Combustion Turbines

Unit	Description	BACT Options	Feasible Options
#60 through #64	Combined cycle combustion turbines	Good combustion practices	Yes
		Oxidation catalyst	Yes
		EMx ™	No

Hyperion identified in the application that the EMx™ system has not been demonstrated to operate successfully with the size of the units being proposed by Hyperion. Hyperion elected to combine the two remaining feasible options. Table 7-77, identifies Hyperion’s proposed control option, the rank of the control option, and the proposed emission limit.

Table 7-77 – Proposed VOC BACT Control and Limit for Combustion Turbines

Unit	Description	Proposed Control	Rank	Proposed Limit
#60 through #64	Combined cycle combustion turbines (syngas, pressure swing adsorption tail gas, and distillate oil)	Oxidation catalyst and good combustion practices	#1	0.017 pounds of volatile organic compounds, reported as propane, per million Btus, heat input, high heating value [1]; and 3.0 parts per million by volume carbon monoxide, corrected to 15% oxygen [2]
	Combined cycle combustion turbines (pressure swing adsorption tail gas, natural gas, and distillate oil)	Oxidation catalyst and good combustion practices	#1	0.017 pounds of volatile organic compounds, reported as propane, per million Btus, heat input, high heating value [1]; and 3.0 parts per million by volume carbon monoxide, corrected to 15% oxygen [2]

[1] – Compliance is based on a 3-hour average, excluding periods of startup, shutdown, or malfunctions; and
[2] – Compliance is based on a 365-day rolling average, including periods of startup, shutdown, or malfunctions;

Based on DENR's review, there are no facilities with equivalent or more stringent limitations than those proposed by Hyperion for the proposed controls. For example, a review of Kentucky Department of Environmental Protection permit to Cash Creek Generation facility issued on January 17, 2008, for the integrated gasification combined cycle system does not note an emission limit. In addition, a review of Illinois EPA's permit to Christian County Generation facility issued on June 5, 2007, for the integrated gasification combined cycle does not note an emission limit.

DENR agrees that the use of an oxidation catalyst and good combustion practices represents the best control option of the BACT analysis for Hyperion's petroleum coke/coal option and natural gas option. DENR also agrees with the emission limit and compliance demonstrations established in Table 7-77.

7.1.4.5 VOC BACT for IGCC Startup Burners

Hyperion is proposing a "maximum coke design case" and "natural gas design case" to fire five combined cycle combustion turbines to generate electricity for the Hyperion's refinery. Under the "maximum coke design case", the system will use eight gasifier startup burners fired with natural gas. In this case, only six will operated at one time with two gasifier startup burners are used as a backup. The "maximum natural gas design case", will use seven gasifier startup burners. In this case, only five will operate at one time and two are used as a backup.

Hyperion identified in its application one option for BACT. Table 7-78 identifies the BACT option for IGCC startup burners and if the option is considered feasible to install. DENR agreed with the first two steps of the BACT analysis.

Table 7-78 – VOC Options and Feasibility for IGCC Startup Burners

Unit	Description	BACT Options	Feasible Options
#51 through #58	Gasifier startup burners	Good combustion practices	Yes
		Oxidation catalyst	No

Hyperion identified in the application that the oxidation catalyst was not technically feasible because of the sporadic operating times of the units and stable, minimum temperatures, needed for the systems. This left only one BACT option which is good combustion practices. Table 7-79, identifies Hyperion's proposed control option, the rank of the control option, and the proposed emission limit.

Table 7-79 – Proposed VOC BACT Control and Limit for IGCC Startup Burners

Unit	Description	Proposed Control	Rank	Proposed Limit
#51 through #58	Gasifier startup burners	Good combustion practices	#1	Work practice requirements, no limit proposed

Based on DENR's review, there are no facilities with equivalent or more stringent limitations than those proposed by Hyperion for the proposed controls. For example, a review of Kentucky Department of Environmental Protection permit to Cash Creek Generation facility issued on January 17, 2008, for the integrated gasification combined cycle system does not note an emission limit. In addition, a review of Illinois EPA's permit to Christian County Generation facility issued on June 5, 2007, for the integrated gasification combined cycle does not note an emission limit.

DENR agrees that good combustion practices are the appropriate control technology choice to represent BACT for gasifier startup burners. Hyperion proposed a work practice standard as BACT that would be based on good combustion practices. In the application, Hyperion describes the amount of time the gasifier startup burners would operate. In each scenario the gasifier startup burners would operate equal to or more than eight hours at a time. A performance test could be conducted during this time period, which would not be due to startup, shutdown, or malfunction of the gasifier startup burner. DENR will establish a volatile organic compound emission limit for each gasifier startup burner. DENR is proposing a BACT emission limit for volatile organic compounds of 0.14 pounds per million Btus, as carbon, excluding startups, shutdowns, and malfunctions of the gasifier startup burner. The proposed limit is based on the emission rates used in the modeling and/or calculations. Compliance with the BACT emission limit for volatile organic compounds shall be based on an average of three test runs based on a performance test.

The BACT emission limit for volatile organic compounds is not applicable during periods of startup, shutdown, or malfunctions. The BACT emission limit for volatile organic compounds during these occurrences will be discussed later.

7.1.4.6 VOC BACT for Generators and Fire Pumps

The BACT analysis for volatile organic compounds for generators and fire pumps was conducted with the BACT analysis for nitrogen oxide (see Section 7.1.3.6).

7.1.4.7 VOC BACT for Refinery and Gasification Flares

Hyperion conducted a BACT analysis for volatile organic compounds being emitted from the petroleum refinery fuel producing units. The gasification flare will be used for the safe disposal of off-specification syngas that is produced during unit startups, shutdowns and malfunctions and that cannot be routed to the combined cycle combustion turbines, the pressure swing adsorption unit, or to another gasifier.

Hyperion identified in its application several options for BACT and identified which options were considered feasible or infeasible. Table 7-80 identifies the BACT options reviewed for refinery flares and gasification flare, and if the options were considered feasible to install. DENR agreed with the first two steps of the BACT analysis.

Table 7-80 – VOC Options and Feasibility for Refinery and Gasification Flares

Unit	Description	BACT Options	Feasible Options
#36 through #40 and #50	Refinery and gasification flares	Flare minimization plan	Yes
		Design specifications	Yes

Hyperion combined the feasible options. Table 7-81, identifies Hyperion's proposed control option, the rank of the control option, and the proposed emission limit.

Table 7-81 – Proposed VOC BACT Control and Limit for Flares

Unit	Description	Proposed Control	Rank	Proposed Limit
#36 through #40 and #50	Refinery and gasification flares	Flare minimization plan and design specifications	#1	Work practice requirements and design requirements in 40 CFR §60.18, no proposed limit

Based on DENR's review, there is one facility and two state rules with an equivalent or more stringent limitation than those proposed by Hyperion for the proposed controls. DENR reviewed each of these to verify the BACT emission limit.

A review of California's South Coast Air Management District's Rule 1118 – Control of Emissions from Refinery Flares amended November 4, 2005, specifies a work practice and design requirement for the operations of the flares (pages 1118-5 through 1118-7). The rule does not specify a numerical limit for flares.

A review of California's Bay Area Air Quality Management District's Regulation 12 Rule 11 – Flare Monitoring at Petroleum Refineries and Regulation 12 Rule 12 – Flares at Petroleum Refineries, specifies a work practice and design requirement for the operations of the flares (12-12-3). The rule does not specify a numerical limit for flares.

A review of Arizona Department of Environmental Quality's permit for the Arizona Clean Fuels Yuma Refinery issued on September 18, 2006, specifies a work practice and design requirements for the operations of the flares (page 401 through 407).

DENR's review indicates that good combustion practices and a flare minimization plan is the appropriate control technology choice for volatile organic compounds to represent BACT for refinery and gasification flares. The operations of a flare are not conducive to conduct a performance test. Therefore, DENR agrees with Hyperion that a numerical volatile organic compounds emission limit is not feasible to implement.

The operations of a refinery may be broke down into two categories used in the discussion for minimizing the flare operations. The first category is for planned or known upsets that occur during periods such as startup or shutdown of operations, maintenance activities, and turnarounds. Oil refineries have been in operation for years in the United States, as such, Hyperion is able to design the facility with a sufficient flare recovery gas system for these periods that flaring of these gases would not be required. The permit will be written to not allow flaring for these operations.

The second category is for unplanned or unknown upsets that occur during a malfunction. For safety reasons and because not every possible upset scenario may be considered, Hyperion needs to have the ability to flare during these unknown events. The permit will be written that allows flaring during unknown upsets caused by malfunctions. However, Hyperion's maintenance activities should take into account reoccurring failures of malfunctioning equipment. Upsets caused by poor maintenance should not be considered malfunctions. The permit will contain language defining the term malfunctions. In addition, when flaring events do occur during a malfunction, Hyperion should review the causes of those flaring events and identify potential solutions to resolve the issue such as an improved maintenance program. The permit will contain language requiring an analysis of the causes for the flaring event during the malfunction.

Unlike the refinery operations, Hyperion is requesting to flare the syngas produced during the startup, shutdown, and malfunctions of the gasification system. There are several reasons why the gasification process is not cost effective or technologically feasible to design a system to capture all the syngas produced during these periods.

For example, the amount of syngas that is produced during these events would overwhelm the refinery gas recovery system. The refinery gas recovery system sends the refinery gas to the process heaters to be burned. The amount of syngas produced would be approximately 4.8 million cubic feet at a heat rate of 1,500 MMBtu per hour. The process heaters are designed at maximum capacity to burn approximately 6.9 million cubic feet of refinery gas at a heat rate of 8,600 MMBtu per hour. Hyperion would need to supplement the syngas with natural gas to increase the heat rate of the gas burned. This would cause the refinery flares to be used. Another example, the syngas would affect the operation of the process heaters because the process heaters are not designed to burn the syngas with a heat input of approximately 300 Btus per cubic foot. The process heaters. are designed to burn refinery gas or designed to burn a gas with a heat input around 1,250 Btus per cubic foot. By burning the syngas, the process heaters. may not be able to meet the proposed emission limitations for nitrogen oxide emissions.

Even if these technical issues are somehow resolved, the cost of collecting the syngas from the gasification system is not cost effective. Hyperion identified that the cost of compressor system for this flare recovery system would have an installed cost greater than $100 million and an annual operational cost of $10 million. The incremental cost of the project would be $400,000 per ton of carbon monoxide reduced, $20 million per ton of sulfur dioxide emission reduced, and $30 million per ton of volatile organic compound emissions reduced. DENR considers the project as not cost effective.

The permit will be written that allows flaring during startup, shutdown, and malfunctions from the gasification system.

7.1.4.8 VOC BACT for Cooling Tower

Hyperion identified in its application several options for BACT and identified which options were considered feasible or infeasible. Table 7-82 identifies the BACT options reviewed for a cooling tower, and if the options were considered feasible to install. DENR agreed with the first two steps of the BACT analysis.

Table 7-82 – VOC Options and Feasibility for Cooling Tower

Unit	Description	BACT Options	Feasible Options
#41	Cooling tower	Leak detection and repair program	Yes

Since there is only one BACT option, the top option is a leak detection and repair program. Table 7-83, identifies Hyperion's proposed control option, the rank of the control option, and the proposed emission limit.

Table 7-83 – Proposed VOC BACT Control and Limit for Cooling Tower

Unit	Description	Proposed Control	Rank	Proposed Limit
#41	Cooling tower	Leak detection and repair program	#1	Work practice standards

Based on DENR's review, there is one facility with an equivalent or more stringent limitation than those proposed by Hyperion for the proposed controls. DENR reviewed each of these to verify the BACT emission limit.

A review of Arizona Department of Environmental Quality's permit for the Arizona Clean Fuels Yuma Refinery issued on September 18, 2006, specifies the requirements for a leak detection program (page 424 through 426).

DENR's review indicates that a leak detection program is the appropriate control technology choice for volatile organic compounds to represent BACT for a cooling tower. DENR agrees with Hyperion that work practice standards should be the BACT emission limit for volatile organic compounds.

7.1.4.9 VOC BACT for Wastewater Treatment Plant

Hyperion conducted a BACT analysis for volatile organic compounds being emitted from the wastewater treatment plant. Hyperion identified two areas in a wastewater treatment plant were volatile organic compounds can be controlled and consist of the wastewater collection system drains and sumps and treatment vessels.

Hyperion identified in its application several options for BACT and identified which options were considered feasible or infeasible. Table 7-84 identifies the BACT options reviewed for the wastewater treatment plant, and if the options were considered feasible to install.   DENR agreed with the first two steps of the BACT analysis.

Table 7-84 – VOC Options and Feasibility for Wastewater Treatment Plant

Unit	Description	BACT Options	Feasible Options

Unit	Description	BACT Options	Feasible Options
#45b	Wastewater collection system (drains and sumps)	Water seals	Yes
		Carbon adsorption	Yes
		Closed-vent system	Yes
#45a	Wastewater treatment vessels	Wastewater stripper	Yes
		Floating roof	Yes
		Catalytic oxidizer	Yes
		Closed-vent system	Yes
#45c	Aeration Tanks	Floating roof	Yes

In the application, Hyperion ranked the feasible control options, which are displayed in Table 7-85.

Table 7-85 – Top VOC Control Options for Wastewater Treatment Plant

Unit	Description	Feasible Options	Rank
#45b	Wastewater collection system (drains and sumps)	Closed-vent and dual carbon canisters	#1
		Water seals	#2
#45a	Wastewater treatment vessels	Wastewater stripper, floating roofs, closed-vent system and catalytic oxidizer	#1
#45c	Aeration Tanks	Floating roof	#1

Hyperion is proposing to implement the #1 ranked option for the wastewater collection system by installing a closed-vent system with dual carbon canisters. The #1 ranked option for the wastewater treatment vessels will also be implemented, except the control system will not include the two aeration tanks. Hyperion cited that the inclusion of these two tanks would be economically prohibitive and the volatile organic compound emission estimated from these tanks (3.6 tons per year) would not justify the cost. Table 7-86, identifies Hyperion's proposed control option, the rank of the control option, and the proposed emission limit.

Table 7-86 – Proposed VOC BACT Control and Limit for Wastewater Treatment Plant

Unit	Description	Proposed Control	Rank	Proposed Limit
#45b	Wastewater collection system(drains and sumps)	Closed-vent and dual carbon canisters	#1	Equipment design standard equivalent to 40 CFR §61.349
#45a	Wastewater treatment vessels	Wastewater stripper	#1	Benzene concentration entering oil/water separators to a flow-weighted annual average of 10 parts per million by weight
		Floating roofs installed on each Equalization and Aeration tank		Equipment design standard equivalent to 40 CFR §61.351
		Closed-vent and		Equipment design standard

Unit	Description	Proposed Control	Rank	Proposed Limit
		catalytic oxidation system for oil/water Separators and Equalization tanks		equivalent to 40 CFR §61.349
#45c	Aeration Tanks	Floating roof	#1	Equipment design standard equivalent

Based on DENR's review, there is one facility and two state rules with equivalent or more stringent limitations than those proposed by Hyperion for the proposed controls. DENR reviewed each of these to verify the BACT emission limit.

A review of California's Santa Barbara Air Quality Control District Rule 325 – Crude Oil Production and Separation specify that a vapor recovery system must obtain 90% removal efficiency (page 325-3).

A review of California's Bay Area Air Quality Management District's Regulation 8 Rule 8 – Wastewater Collection and Separation Systems specify that a vapor recovery system and control device must obtain 70 to 95% removal efficiency (page 8-8-6 through 8-8-8).

A review of Arizona Department of Environmental Quality's permit for the Arizona Clean Fuels Yuma Refinery issued on September 18, 2006, specifies that the thermal oxidizer is to be designed with a volatile organic compound destruction efficiency of 99.9 percent or greater at an inlet volatile organic compound concentration in excess of 20,000 parts per million by volume and to achieve an outlet volatile organic compound concentration of 20 parts per million by volume or less when the inlet volatile organic compound concentration is less than 20,000 parts per million by volume (page 348). The design value of 99.9 percent efficiency does not necessarily mean that the thermal oxidizer is required to actually meet 99.9 percent destruction at all operations.

DENR agrees with the proposed control options for the waste water treatment plant. DENR disagrees with the emission limitation for the thermal oxidizer controlling emissions from the oil/water separator and dissolved air flotation units. 40 CFR Part 61 Subpart FF lists several different compliance limits depending on the operations. DENR believes that the thermal oxidizer should meet a 98% destruction efficiency or 20 parts per million by weight volatile organic compounds as carbon, whichever is the least stringent.

7.1.4.10 VOC BACT for Coke Drum Steam Vents

After the coking process is completed, the coke drums are steamed out and cooled. Once the cooling process has completed, the coke drum is depressurized to the atmosphere through a steam vent. Hyperion conducted a BACT analysis for during the periods when the coke drum is depressurized to the atmosphere.

Hyperion identified in its application several options for BACT and identified which options were considered feasible or infeasible. Table 7-87 identifies the BACT options reviewed for the coke steam vents, and if the options were considered feasible to install. DENR agreed with the first two steps of the BACT analysis.

Table 7-87 – VOC Options and Feasibility for Coke Drum Steam Vents

Unit	Description	BACT Options	Feasible Options
#34 and #35	Coke drum steam vents	Design requirement of 2 pounds per square inch, gauged	No
		Design requirement of 5 pounds per square inch, gauged	Yes

Hyperion notes that EPA recently made a determination in the preamble to 40 CFR Part 60, Subpart Ja that it is technically infeasible to recover the coke drum blow down vapors at a drum pressure less than 5 pounds per square inch, gauged. In the application, Hyperion did not rank the BACT options in this case since there is only one feasible option. Since there is only one option, the design requirement of 5 pounds per square inch, gauged, is the top volatile organic compound control option for the coke drum steam vents.

Table 7-88, identifies Hyperion's proposed control option, the rank of the control option, and the proposed emission limit.

Table 7-88 – Proposed VOC BACT Control and Limit for Coke Drum Steam Vents

Unit	Description	Proposed Control	Rank	Proposed Limit
#34 and #35	Coke drum steam vents	Design requirement of 5 pounds per square inch, gauged	#1	Work design practice standards in accordance with 40 CFR Part 60, Subpart Ja

Based on DENR's review, there are no facilities with equivalent or more stringent limitations than those proposed by Hyperion for the proposed controls. A review of Arizona Department of Environmental Quality's permit for the Arizona Clean Fuels Yuma Refinery issued on September 18, 2006, does not specify a standard for the coke drum depressuring vents.

DENR's review indicates that the design requirement that each coke drum be depressurized to 5 pounds per square inch, gauged, before the exhaust gases can be vented to atmosphere is the appropriate control technology choice for volatile organic compounds to represent BACT for a coke drum steam vents. DENR agrees with Hyperion that the proposed BACT volatile organic compounds emission limit should be based on the work practice standards outlined in 40 CFR Part 60, Subpart Ja.

7.1.4.11 VOC BACT for Tank Farm

Hyperion identified in its application several options for BACT and identified which options were considered feasible or infeasible. Table 7-89 identifies the options reviewed for the tank farm and the options that were considered feasible to install. DENR agreed with the first two steps of the BACT analysis.

Table 7-89 – VOC Options and Feasibility for Tank Farms

Unit	Description	BACT Options	Feasible Options
Unit #71 through #174, except Unit #152 through #155	Storage tanks	Fuel gas system	Yes
		Internal floating roof plus thermal oxidizer	Yes
		Thermal oxidizer	Yes
		Internal or external floating roof	Yes
		No controls	Yes
Unit #152 and #153	Storage tanks	Fuel gas system	Yes
		Thermal oxidizer	Yes
		No controls	Yes
Unit #154 and #155	Storage Tanks	Thermal oxidizer	Yes
		No controls	Yes

In the application, Hyperion ranked the feasible control options, proposed a control option, and proposed an emission limit. Table 7-90 identifies the feasible options, the estimated control efficiencies by DENR, and rank for each option.

Table 7-90 – Top VOC BACT Control Options for Tank Farm

Unit	Description	BACT Options	Control Efficiency	Rank
Unit #71 through #174, except #140, #149 through #155and #163	Storage tanks	Fuel gas system	100%	#1
		Internal floating roof plus thermal oxidizer	99+%	#2
		Thermal oxidizer	98%	#3
		Internal or external floating roof	60% to 99% [1]	#4
		No controls	0%	#5
Unit #140, #149 through #151 and #163	Storage tanks	Fuel gas system	100%	#1
		Internal floating roof plus thermal oxidizer	99+%	#2
		Thermal oxidizer	98%	#3
		Internal or external floating roof	60% to 99% [1]	#4
		No controls	0%	#5
Unit #152 and #153	Storage tanks	Fuel gas system	100%	#1
		Thermal oxidizer	98%	#2
		No controls	0%	#3
Unit #154 and #155	Storage tanks	Thermal oxidizer	98%	#2
		No controls	0%	#2

[1] – Control efficiency was determined from AP-42, Section 7.12.1, 11/06.

Table 7-91 identifies Hyperion's proposed control option, the rank of the control option, and the proposed emission limit.

Table 7-91 – Proposed VOC BACT Control and Limit for Tank Farm

Unit	Description	Proposed Control	Rank	Proposed Limit
Unit #71 through #174, except #149 through #155 and #163	Storage tanks	Internal floating roof	#4	Work practice standards
Unit #140, #149 through #151 and #163	Storage tanks	No controls	#5	No proposed limit
Unit #152 and #153	Storage tanks	No controls	#3	No proposed limit
Unit #154 and #155	Storage tanks	No controls	#2	No proposed limit

Based on DENR's review, there is one facility and a state rule with equivalent or more stringent limitations than those proposed by Hyperion for the proposed controls. DENR reviewed each of these to verify the BACT emission limit.

A review of California's Santa Barbara Air Quality Control District Rule 325 – Crude Oil Production and Separation specify that a vapor recovery system must obtain 90% removal efficiency (page 325-3). DENR review indicates that Santa Barbara Air Quality Control District does not have an oil refinery. Therefore, DENR verified with Santa Barbara Air Quality Control District that this rule would apply to an oil refinery's tank farm.

A review of Arizona Department of Environmental Quality's permit for the Arizona Clean Fuels Yuma Refinery issued on September 18, 2006, specifies that the thermal oxidizer is to be designed with a volatile organic compound destruction efficiency of 99.9 percent or greater at an inlet volatile organic compound concentration in excess of 20,000 parts per million by volume and to achieve an outlet volatile organic compound concentration of 20 parts per million by volume or less when the inlet volatile organic compound concentration is less than 20,000 parts per million by volume (page 348). The design value of 99.9 percent efficiency does not necessarily mean that the thermal oxidizer is required to actually meet 99.9 percent destruction at all operations.

Based on DENR's review of applications for ethanol plants, oil and gas production facilities, coating operations, etc. in South Dakota indicate that the cost range for a thermal oxidizer is approximately 1 to 2 million dollars. Hyperion's application indicates that the cost for the thermal oxidizer for the wastewater treatment facility is approximately 1 million dollars. DENR conducted a more detailed review of Hyperion's cost analysis for the thermal oxidizer(s) to control volatile organic compound emissions from the storage tanks.

Hyperion's application requested the flexibility to store other petroleum liquids than that specifically identified in the application for each tank as identified in Section 3.7. By requesting this flexibility, Hyperion has agreed to install floating roofs on storage tanks that would not have been required to install a floating roof as noted in Section 3.7. Examples of the types of tanks that would not have required a floating roof are as follows: Tank ID's IP14, IP15, IP16, IP17, IP19, IP20, IP22, RP 10, RP11, SS9, SS10, SS20, and SS21.

Tank ID	Stored Liquid	Uncontrolled Tons	Controlled Tons	Total Cost $
IP14-1	Inalk Alkylate	69.28	0.3	500,000
IP14-2	Inalk Alkylate	69.28	0.3	500,000
IP15-1	Inalk C12+ Stream	0.02	0.06	300,000
IP16-1	Straight Run Kerosene	1.78	0.17	800,000
IP16-2	Straight Run Kerosene	1.78	0.17	800,000
IP17-1	Straight Run Diesel	1.43	0.22	800,000
IP17-2	Straight Run Diesel	1.43	0.22	800,000
IP17-3	Straight Run Diesel	1.43	0.22	800,000
IP19-1	Coker LCGO	0.69	0.27	800,000
IP19-2	Coker LCGO	0.69	0.27	800,000
IP20-1	DHDS ULSD Product	2.94	0.35	1,400,000
IP20-2	DHDS ULSD Product	2.94	0.35	1,400,000
IP20-3	DHDS ULSD Product	2.94	0.35	1,400,000
IP22-1	Hydrocracker Diesel	2.94	0.35	1,400,000
IP22-2	Hydrocracker Diesel	2.94	0.35	1,400,000
RP10-1	Jet Fuel (HC Kerosene)	2.93	0.15	1,400,000
RP10-2	Jet Fuel (HC Kerosene)	2.93	0.15	1,400,000
RP10-3	Jet Fuel (HC Kerosene)	2.93	0.15	1,400,000
RP11-1	ULSD Diesel Product	2.6	0.18	1,400,000
RP11-2	ULSD Diesel Product	2.6	0.18	1,400,000
RP11-3	ULSD Diesel Product	2.6	0.18	1,400,000
RP11-4	ULSD Diesel Product	2.6	0.18	1,400,000
RP11-5	ULSD Diesel Product	2.6	0.18	1,400,000
RP11-6	ULSD Diesel Product	2.6	0.18	1,400,000
RP11-7	ULSD Diesel Product	2.6	0.18	1,400,000
RP11-8	ULSD Diesel Product	2.6	0.18	1,400,000
RP11-9	ULSD Diesel Product	2.6	0.18	1,400,000
RP11-10	ULSD Diesel Product	2.6	0.18	1,400,000
RP11-11	ULSD Diesel Product	2.6	0.18	1,400,000
SS9-1	Amine (Rich)	0.61	0.06	1,240,000
SS10-1	Amine Swing Tank	0.61	0.06	1,240,000
SS20-1	Kerosene Product	0.13	0.23	290,000
SS21-1	Diesel Product	0.1	0.23	290,000

Hyperion submitted subsequent cost information for the above tanks. Hyperion's cost analysis notes that those 33 tanks noted above would have a total cost of $36,560,000. Those tanks would have an uncontrolled emission rate of 201.4 tons per year and a controlled emission rate of 7 tons per year. Using the equation 7-1, the annualized cost is $4,014,091.

Equation 7-1

$$A = P\left(\frac{i(1+i)^n}{(1+i)^n - 1}\right)$$

Where A = Annualized Cost
P = Total Cost – $36,560,000
i = Interest Rate – 7 percent in decimal form
n = Life expectancy of the floating roof – 15 years

The cost per ton of emission reduction is achieved by dividing the annualized cost by the emission reductions generated by the floating roof (i.e. 4,014,091 / 194.4). The annualized cost for these tanks is $20,649 per ton of volatile organic compounds reduced.

With the request for operational flexibility for the storage tanks, Hyperion has established a baseline for what would be considered cost effective for reducing volatile organic compound emission in the tank farm at approximately $20,000 per ton.

Hyperion's cost analysis estimates that the total cost of the thermal oxidizer, including installation, electrical, etc. would be approximately $7,100,000 to $7,900,000. Hyperion's cost analysis indicates just the equipment cost of the thermal oxidizer(s) by themselves would cost $1,000,000 to $1,100,000. Hyperion's cost analysis notes that the cost factor is based on process average for the refinery and not specific for the thermal oxidizer. EPA's 6th Edition Control Cost Manual indicates that the total cost of the thermal oxidizer(s) should be approximately 1.9 times the equipment cost of the thermal oxidizer. Based on EPA's Control Cost Manual, the total cost, which would include installation, electrical, etc., for the thermal oxidizers would be $1,900,000 to $2,100,000.

Hyperion's total cost for the thermal oxidizer project, which includes the thermal oxidizer, storage tank piping, and electrical/instrumentation, would be approximately $18,500,000 to $24,700,000. Hyperion's cost analysis also notes that the cost estimate has an accuracy of +/- 50%. This means the thermal oxidizer project could range from $9,235,000 to $49,400,000.

DENR considered the following six scenarios in determining a cost effectiveness.

1) Using Hyperion's cost analysis in the "all tanks" spreadsheet submitted August 28, 2008, representing 89 tanks, DENR changed the cost for the thermal oxidizer portion to $2,000,000. The spreadsheet identifies the total cost for the project would be $18,875,000. Using Hyperion's cost analysis spreadsheet submitted August 27, 2008 for "Case 1", the incremental cost is $22,363 per ton of volatile organic compounds reduced.

2) Using Hyperion's cost analysis in the "lighter than jet" spreadsheet submitted August 28, 2008, representing 59 tanks, DENR changed the cost for the thermal oxidizer portion to $2,000,000. The spreadsheet identifies the total cost for the project would be $13,321,000. Using Hyperion's cost analysis spreadsheet submitted August 27, 2008 for "Case 2", the incremental cost is $16,815 per ton of volatile organic compounds reduced.
3) Using Hyperion's cost analysis spreadsheet submitted August 27, 2008 for "Case 1", which represents 89 tanks, DENR changed the cost of the project to $12,370,000. This cost represents approximately 50% of the projected cost of the project. The incremental cost is $15,082 per ton of volatile organic compounds reduced.
4) Using Hyperion's cost analysis spreadsheet submitted August 27, 2008 for "Case 2", which represents 59 tanks, DENR changed the cost of the project to $9,235,000. This cost represents approximately 50% of the projected cost of the project. The incremental cost is $11,937 per ton of volatile organic compounds reduced.
5) Using Hyperion's cost analysis in the "all tanks" spreadsheet submitted August 28, 2008, representing 89 tanks, DENR changed the cost for the thermal oxidizer portion to $2,000,000. DENR also changed the number of tanks from 89 to 97. The additional eight tanks include the tanks that would store, atmospheric gas oil (IP18-1), vacuum gas oil (IP23-1, IP23-2, and IP23-3), heavy coker gas oil (IP24-1 and IP24-2), and vacuum residuum (IP25-1 and IP25-2). These tanks would not have internal floating roofs and would emit approximately 48.9 to 132.1 tons of volatile organic compounds per year. The 83 tons per year difference is due Hyperion's assumption that cooling and filtration system used on the vacuum residuum tanks would achieve 90% reduction. The spreadsheet identifies the total cost for the project would be $19,579,000. Using Hyperion's cost analysis spreadsheet submitted August 27, 2008 for "Case 1", DENR changed the tons of volatile organic compounds from 100.1 to 149 to account for the additional 8 tanks. The incremental cost calculated by the spreadsheet is $15,553 per ton of volatile organic compounds reduced.
6) Using Hyperion's cost analysis in the "lighter than jet" spreadsheet submitted August 28, 2008, representing 59 tanks, DENR changed the cost for the thermal oxidizer portion to $2,000,000. DENR also changed the number of tanks from 59 to 67. The additional eight tanks include the tanks that would store, atmospheric gas oil (IP18-1), vacuum gas oil (IP23-1, IP23-2, and IP23-3), heavy coker gas oil (IP24-1 and IP24-2), and vacuum residuum (IP25-1 and IP25-2). These tanks would not have internal floating roofs and would emit approximately 48.9 to 132.1 tons of volatile organic compounds per year. The 83 tons per year difference is due Hyperion's assumption that cooling and filtration system used on the vacuum residuum tanks would achieve 90% reduction. The spreadsheet identifies the total cost for the project would be $14,784,000. Using Hyperion's cost analysis spreadsheet submitted August 27, 2008 for "Case 2", DENR changed the tons of volatile organic compounds from 93.9 to 142.8 to take into account for the additional 8 tanks. The incremental cost is $12,269 per ton of volatile organic compounds reduced.

Based on DENR's experience with thermal oxidizers and its review, DENR disagrees that the thermal oxidizer project is not cost effective. In addition, five of the six scenarios that DENR considered calculated an incremental cost less than the incremental cost of the floating roofs that Hyperion proposed to install as BACT for operational flexibility. DENR considers the use of a thermal oxidizer(s) is considered BACT for the storage tanks. The thermal oxidizer will be required to achieve 98 percent control or 20 parts per million by volume, which ever is the least stringent. Demonstrating compliance with the BACT emission limit for volatile organic compounds will be demonstrated by a 3-hour average based on a stack performance test.

DENR does agree that cost effectiveness for the tank varies depending on the type of product that is being stored. To allow Hyperion its operational flexibility, the permit will be drafted with two operating scenarios:

1) All storage tanks must be routed to a thermal oxidizer; or
2) All storage tanks with floating roofs storing a liquid with a maximum true vapor pressure greater than or equal to 0.3 pounds per square inch must be routed to a thermal oxidizer and the other storage tanks with floating roofs would be limited to storing a liquid with a maximum true vapor pressure less than 0.3 pounds per square inch.

The BACT emission limit for volatile organic compounds is not applicable during periods of startup, shutdown, or malfunctions. The BACT volatile organic compound emission limit during these occurrences will be discussed later.

7.1.4.12 VOC BACT for Loading Racks

Hyperion conducted a BACT analysis for the loading racks. The BACT analysis required a review of volatile organic compounds.

Hyperion identified in its application several options for BACT and identified which options were considered feasible or infeasible. Table 7-92 identifies the BACT options reviewed for the loading racks and if the options were considered feasible to install. DENR agreed with the first two steps of the BACT analysis.

Table 7-92 – VOC Options and Feasibility for Loading Racks

Unit	Description	BACT Options	Feasible Options
#43	Railcar loading rack	Condensation	Yes
		Carbon adsorption	Yes
		Incineration	Yes
#44	Truck loading rack	Condensation	Yes
		Carbon adsorption	Yes
		Incineration	Yes

Table 7-93 identifies the feasible options, the estimated control efficiencies by DENR, and rank for each BACT option.

Table 7-93– Proposed VOC BACT Control Options for Loading Racks

Unit	Description	Feasible Options	Control Efficiency	Rank
#43	Railcar loading rack	Condensation	99% [1]	#1
		Carbon adsorption	0 to 99% [3]	#2
		Incineration	50% [2]	#3

Unit	Description	Feasible Options	Control Efficiency	Rank
#44	Truck loading rack	Condensation	99% [1]	#1
		Carbon adsorption	0 to 99% [3]	#2
		Incineration	50% [2]	#3

[1] – EPA Technical Bulletin Choosing an adsorption system for VOC, May 1999, page 16;
[2] – EPA, SIP Planning Toolkit: Applicable Control Measures, Stationary NOx Measures with control efficiency and dollars per ton, 2006; and
[3] – Identification of Point Source Emission Controls and Determination of Their Efficiencies and Costs, California Air Board Resources Board and the California Appendix B: Control Technology Descriptions and Cost Data, page 142.

Table 7-94, identifies Hyperion's proposed control option, the rank of the control option, and the proposed emission limit.

Table 7-94 – Proposed VOC BACT Control and Limit for Loading Rack

Unit	Description	Proposed Control	Rank	Proposed Limit
#43	Railcar loading rack	Carbon adsorption	#2	1.25 pounds per million gallons of product loaded based on a 3-hour rolling average
#44	Truck loading rack	Carbon adsorption	#2	1.25 pounds per million gallons of product loaded based on a 3-hour rolling average

Based on DENR's review, there is one facility and a state rule(s) with equivalent or more stringent limitations than those proposed by Hyperion for the proposed controls. DENR reviewed each of these to verify the BACT emission limit.

A review of California's Bay Area Air Quality Managemen District's Regulation 8 Rule 6 – Organic Liquid Bulk Terminals and Bulk Plants, Regulation 8 Rule 33 – Gasoline Bulk Terminal and Gasoline Delivery Vehicles, and Regulation 8 Rule 39 – Gasoline Bulk Plants specify an emission limit that varies 80 to 500 pounds per million gallons loaded.

A review of Arizona Department of Environmental Quality's permit for the Arizona Clean Fuels Yuma Refinery issued on September 18, 2006, specifies an emission limit of 1.25 pounds per million gallons of gasoline loaded and 22 pounds per million gallons of distillate oil loaded (page 290).

DENR agrees with the BACT control technique for the truck and railcar loading racks and the process of demonstrating compliance.

7.1.4.13 VOC BACT for Fugitive Sources

Hyperion conducted a BACT analysis for volatile organic compound emissions produced from leaking equipments such as valves, pumps, and compressors.

Hyperion identified in its application several options for BACT and identified which options were considered feasible or infeasible. Table 7-95 identifies the BACT options reviewed for fugitive sources and if the options were considered feasible to install. DENR agreed with the first two steps of the BACT analysis.

Table 7-95 – VOC Options and Feasibility for Fugitive Sources

Description	BACT Options	Feasible Options
Equipment Leaks	Leak detection and repair program	Yes

Since there is only one option, the top option is a leak detection and repair program. Table 7-96, identifies the proposed control option, the rank of the control option, and the proposed emission limit.

Table 7-96 – Proposed VOC BACT Control and Limit for Fugitive Sources

Description	Proposed Control	Rank	Proposed Limit
Equipment Leaks	Leak detection and repair program	#1	Work practice and design requirements

Based on DENR's review, there is one facility and two state rules with equivalent or more stringent limitations than those proposed by Hyperion for the proposed controls. DENR reviewed each of these to verify the BACT emission limit.

A review of California's South Coast Air Management District's Rule 1173 – Control of Volatile Organic Compound Leaks and Releases from Components at Petroleum Facilities and Chemical Plants specifies a leak detection and repair program for valves, pumps, etc.

A review of California's Bay Area Air Management District's Regulation 8 Rule 18 – Equipment Leaks specifies a leak detection and repair program for valves, pumps, etc.

A review of Arizona Department of Environmental Quality's permit for the Arizona Clean Fuels Yuma Refinery issued on September 18, 2006, specifies a leak detection and repair program for valves, pumps, etc. (page 367).

DENR agrees that a leak detection and repair program is BACT for fugitive volatile organic compound emissions.

7.1.5 BACT Analysis for Carbon Monoxide

7.1.5.1 Carbon monoxide BACT for Process Heaters

Hyperion identified in its application several options for BACT and identified which options were considered feasible or infeasible. Table 7-97 identifies the BACT options reviewed for small and large process heaters and if the options were considered feasible to install. DENR agreed with the first two steps of the BACT analysis.

Table 7-97 – Carbon Monoxide Options and Feasibility for Process Heaters

Unit	Description	BACT Options	Feasible Options
#1 through #30	Process heaters	Good combustion practices	Yes
		Oxidation catalyst	Yes

In the application, Hyperion explains that the process heater temperatures are not optimal for an oxidation catalyst and the presence of sulfur dioxide and sulfates will cause excessive corrosion. Therefore Hyperion states that the oxidation catalyst is technically infeasible.

Since there is only one option, good combustion practice is the top carbon monoxide control option for process heaters. Table 7-98, identifies Hyperion's proposed control option, the rank of the control option, and the proposed emission limit.

Table 7-98 – Proposed Carbon Monoxide BACT Control and Limit for Process Heaters

Unit	Description	Proposed Control	Rank	Proposed Limit
#1 through #30	Large process heaters	Good combustion practices	#1	0.010 pounds per million Btus [1]

[1] – Compliance is based on a 24-hour rolling average, excluding startups, shutdowns, and malfunctions. Compliance is based on a 365-day rolling average, including startups, shutdowns, and malfunctions.

Based on DENR's review, there are at four facilities and a state rule with equivalent or more stringent limitations than those proposed by Hyperion for the proposed controls. DENR reviewed each of these to verify the BACT emission limit.

A review of California's Bay Area Air Quality Management District's Regulation 9 Rule 10 – Nitrogen Oxides and Carbon Monoxide from Boilers, Steam Generators and Process Heaters in Petroleum Refineries notes an emission limit of 400 parts per million by volume on a dry basis corrected to 3 percent oxygen, which is approximately 0.3 pounds per million Btus (page 9-10-5).

A review of Arizona Department of Environmental Quality's permit for the Arizona Clean Fuels Yuma Refinery issued on September 18, 2006, notes that the emission limit for the process heaters is 0.018 to 0.04 pounds per million Btus. (identified through the permit but starting on page 23).

A review of Texas Commission on Environmental Quality's preliminary technical review for the permit to Exxon Corporation's Exxon Bay Refinery issued on May 5, 1999, notes the emission limits are based on carbon monoxide emission rate of 10 parts per million by volume (page 1). If this limit is based on a dry basis, the limit converts to approximately 0.007 pounds per million Btus. If this limit is based on a wet basis, the limit converts to approximately 0.009 pounds per million Btus. A review of the Texas Commission on Environmental Quality's permit identifies the allowable emission rates indicate an emission rate of 0.009 pounds per million Btus (page 1.)

A review of South Coast Air Quality Management District's permit to Ceneco Refining Company for its Santa Fe Springs Refinery issued on November 17, 2000, an emission limit of 12 pounds per day, which equates to approximately 0.01 pounds per million Btus (page 221). South Coast Air Quality Management District's BACT documentation notes that the emission limit is 10 parts per million by volume at 3 percent oxygen. If this limit is based on a dry basis, the limit converts to approximately 0.007 pounds per million Btus. If this limit is based on a wet basis, the limit converts to approximately 0.009 pounds per million Btus.   As noted in Lakeland Processing Company's Audit document revised March 2005 (page 9), the refinery has been in existence since the 1930's. Powerine Oil Company operated from 1936 until 1984 when the refinery went into bankruptcy in 1984 and ceased refinery operations. The refinery emerged from bankruptcy in 1986 and resumed refining activities until 1995. Cenco Refining Company purchased the refinery in 1998 with plans to resume refining. In 2002, Cenco Refining Company decided not to reopen the refinery but instead decided to redevelop the site for other uses such as a non-hazardous liquid waste treatment facility.

A review of Louisiana Department of Environmental Quality permit to Conoco Phillips Company's Lake Charles Refinery issued on September 20, 2002, the emission limit for the process heaters is in pounds per hour, which equate to approximately 0.02 pounds per million Btus.

DENR agrees that good combustion practice is BACT for the process heaters. In DENR's review, the BACT emission limit for carbon monoxide ranged from 0.007 to 0.04 pounds per million Btus for process heaters. DENR disagrees with Hyperion's proposed carbon monoxide emission limit and is proposing a BACT emission limit for carbon monoxide of 0.007 pounds per million Btus. DENR agrees will basing compliance on a 24-hour rolling average, except during periods of startup, shutdown, and malfunctions and on a 365-day rolling average, including periods of startup, shutdown, and malfunctions.

7.1.5.2 Carbon Monoxide BACT for Catalyst Regenerators

Hyperion identified in its application several options for BACT and identified which options were considered feasible or infeasible. Table 7-99 identifies the BACT options reviewed for the catalyst regenerators and if the options were considered feasible to install. DENR agreed with the first two steps of the BACT analysis.

Table 7-99 – Carbon Monoxide Options and Feasibility for Catalyst Regenerators

Unit	Description	BACT Options	Feasible Options

Unit	Description	BACT Options	Feasible Options
#31	Number one platformer catalyst regenerator	Work practice standards	Yes
		Thermal oxidation	No
#32	Number two platformer catalyst regenerator	Work practice standards	Yes
		Thermal oxidation	No
#33	Oleflex catalyst regenerator	Work practice standards	Yes
		Thermal oxidation	No

Hyperion indicated in the application that the size of the catalyst regenerators and operating temperature result in the thermal oxidation control is technically infeasible. Since there is only one option, work practice standards is the top nitrogen oxide control option for catalyst regenerators. Table 7-100, identifies Hyperion's proposed control option, the rank of the control option, and the proposed emission limit.

Table 7-100 – Proposed Carbon Monoxide BACT Control and Limit for Catalyst Regenerators

Unit	Description	Proposed Control	Rank	Proposed Limit
#31	Number one platformer catalyst regenerator	Work practice standards	#1	0.5 pounds per hour
#32	Number two platformer catalyst regenerator	Work practice standards	#1	0.5 pounds per hour
#33	Oleflex catalyst regenerator	Work practice standards	#1	0.1 pounds per hour

Based on DENR's review, there is one facility with equivalent or more stringent limitations than those proposed by Hyperion for the proposed controls. DENR reviewed each of these to verify the BACT emission limit.

A review of Arizona Department of Environmental Quality's permit for the Arizona Clean Fuels Yuma Refinery issued on September 18, 2006, establishes an emission limit of 0.5 pounds per hour for carbon monoxide (page 82).

DENR review indicates that the work practice standard is the appropriate control technology choice to represent BACT for the catalyst regenerators. DENR agrees that the emission limits proposed for catalyst regenerators identified in Table 7-100.

Demonstrating compliance with the BACT emission limit for carbon monoxide was not specified by Hyperion for the catalyst regenerators. DENR proposes compliance be demonstrated by a 3-hour average based on a stack performance test.

The BACT emission limit for carbon monoxide is not applicable during periods of startup, shutdown, or malfunctions. The BACT carbon monoxide emission limit during these occurrences will be discussed later.

7.1.5.3 Carbon Monoxide BACT for Sulfur Recovery Plant

The air emissions from the sulfur recovery plant will be controlled by six thermal oxidizers (Unit #42a, #42b, #42c, #42d, and #42e). Hyperion is proposing to operate a maximum of four thermal oxidizers at one time. As such, a minimum of two thermal oxidizers are being installed as a backup.

Hyperion identified in its application several options for BACT and identified which options were considered feasible or infeasible. Table 7-101 identifies the BACT options reviewed for the sulfur recovery plant and if the options were considered feasible to install. DENR agreed with the first two steps of the BACT analysis.

Table 7-101 – Carbon Monoxide Options and Feasibility for Sulfur Recovery Plant

Unit	Description	BACT Options	Feasible Options
#42	Sulfur recovery plant's thermal oxidizer	Good combustion practices	Yes
		Oxidation catalyst	No

In the application, Hyperion explains that the presence of sulfur dioxide will foul or poison the catalyst. Therefore Hyperion states that the oxidation catalyst is technically infeasible. Since there is only one option, good combustion practice is the top carbon monoxide control option for sulfur recovery plant. Table 7-102, identifies Hyperion's proposed control option, the rank of the control option, and the proposed emission limit.

Table 7-102 – Proposed Carbon Monoxide BACT Control and Limit for Sulfur Recovery Plant

Unit	Description	Proposed Control	Rank	Proposed Limit
#42	Sulfur recovery plant's thermal oxidizer	Good combustion practices	#1	Use hydrogen sulfide limit as surrogate

Based on DENR's review, there are two facilities with equivalent or more stringent limitations than those proposed by Hyperion for good combustion practices. DENR reviewed each of these to verify the BACT emission limit.

A review of Louisiana Department of Environmental Quality's permit for Citigo Petroleum Corporation's Lake Charles Refinery issued September 20, 2002, indicates that the emission limit is 12.4 pounds per hour and based on a combustion device approximately 40 million Btus per hour, which equates to approximately 0.3 pounds per million Btus (page 19).

A review of Arizona Department of Environmental Quality's permit for the Arizona Clean Fuels Yuma Refinery issued on September 18, 2006, does not establish an emission limit for carbon monoxide (page 206).

DENR agrees that good combustion practices are the appropriate control technology choice to represent BACT for the thermal oxidizer associated with the sulfur recovery plant. However, DENR disagrees that the emission limit proposed for good combustion practices represents the appropriate emission limit for BACT. Hyperion also proposed good combustion practices for particulate matter and proposed an emission limit and not a different pollutant as a surrogate. In addition, DENR's review of other permits for refineries demonstrates emission limits for carbon monoxide. Therefore, DENR believes in this instance that a carbon monoxide limit should be established. DENR review indicates that the carbon monoxide emission limit should be 0.08 pounds per million Btus based on the hourly emission rate used in the modeling. Demonstrating compliance with the BACT emission limit for carbon monoxide shall be demonstrated by a 3-hour rolling average, excluding periods of startup, shutdown, and malfunctions and a 365-day average, including periods of startup, shutdown, and malfunctions.

7.1.5.4 Carbon Monoxide BACT for IGCC Combustion Turbines

Hyperion's petroleum coke production design by itself is not sufficient to run the power plant at full capacity. Hyperion is proposing a "maximum coke design case" and "natural gas design case" to fire five combined cycle combustion turbines to generate electricity for Hyperion's refinery. Under the "maximum coke design case", the combustion turbines will be fired with syngas and pressure swing adsorption tail gas derived from petroleum coke and/or coal. Also under this scenario, additional petroleum coke or coal will be purchased to produce the additional fuel demand necessary for the power plant.

The "natural gas design case" will burn natural gas and pressure swing adsorption tail gas derived from the petroleum coke and/or coal. Instead of purchasing additional petroleum coke or coal to produce additional pressure swing adsorption tail gas, under the "natural gas design case", natural gas will be purchased to supplement the fuel demand for the power plant.

Hyperion identified in its application several options for BACT and identified which options were considered feasible or infeasible. Table 7-103 identifies the BACT options reviewed for the IGCC combustion turbines and if the options were considered feasible to install. DENR agreed with the first two steps of the BACT analysis.

Table 7-103 – Carbon Monoxide Options and Feasibility for Combustion Turbines

Unit	Description	BACT Options	Feasible Options
#60 through #64	Combined cycle combustion turbines	Good combustion practices	Yes
		Oxidation catalyst	Yes
		EMx ™	No

Hyperion identified in the application that the EMx™ system has not been demonstrated to operate successfully with the size of the units being proposed by Hyperion. Hyperion elected to combine the two remaining feasible options. Table 7-104, identifies Hyperion's proposed control option, the rank of the control option, and the proposed emission limit.

Table 7-104 – Proposed Carbon Monoxide BACT Control and Limit for Combustion Turbines

Unit	Description	Proposed Control	Rank	Proposed Limit
#60 through #64	Combined cycle combustion turbines (syngas, pressure	Oxidation catalyst and good combustion practices	#1	3.0 parts per million by volume, corrected to 15% oxygen [1]

Unit	Description	Proposed Control	Rank	Proposed Limit
	swing adsorption tail gas, and ultra low sulfur distillate oil)			
	Combined cycle combustion turbines (pressure swing adsorption tail gas, natural gas, and ultra low sulfur distillate oil)	Oxidation catalyst and good combustion practices	#1	3.0 parts per million by volume, corrected to 15% oxygen [1]

[1] – Compliance is based on a 3-hour average, excluding periods of startup, shutdown, or malfunctions; and compliance is based on a 365-day rolling average, including periods of startup, shutdown, or malfunctions.

Based on DENR's review, there are two facilities with equivalent or more stringent limitations than those proposed by Hyperion for the proposed controls. DENR reviewed each of these to verify the BACT emission limit.

A review of Kentucky Department of Environmental Protection permit to Cash Creek Generation facility issued on January 17, 2008, for the integrated gasification combined cycle system notes an emission limit of approximately 0.05 pounds per million Btus (page 3).

A review of Illinois EPA's permit to Christian County Generation facility issued on June 5, 2007, for the integrated gasification combined cycle notes an emission limit of approximately 0.05 pounds per million Btus (page 28).

DENR agrees that the use of an oxidation catalyst and good combustion practices represents the best control option of the BACT analysis for Hyperion's petroleum coke/coal option and natural gas option. For comparison purposes, DENR converted the carbon monoxide limit in parts per million to pounds per million Btus using 40 CFR Part 60, Appendix A, Method 19, which equaled 0.007 pounds per million Btus. Hyperion's proposed carbon monoxide limit is more stringent then BACT emission limits for carbon monoxide that DENR reviewed. DENR agrees with the emission limit and compliance demonstrations established in Table 7-104.

7.1.5.5 Carbon Monoxide BACT for IGCC Startup Burners

Hyperion is proposing a "maximum coke design case" and "natural gas design case" to fire five combined cycle combustion turbines to generate electricity for the Hyperion's refinery. Under the "maximum coke design case", the system will use eight gasifier startup burners fired with natural gas. In this case, only six will operated at one time with two gasifier startup burners are used as a backup. The "maximum natural gas design case", will use seven gasifier startup burners. In this case, only five will operate at one time and two are used as a backup.

Hyperion identified in its application several options for BACT. Table 7-105 identifies the BACT option for IGCC startup burners and if the option is considered feasible to install. DENR agreed with the first two steps of the BACT analysis.

Table 7-105 – Carbon Monoxide Options and Feasibility for IGCC Startup Burners

Unit	Description	BACT Options	Feasible Options
#51 through #58	Gasifier startup burners	Good combustion practices	Yes
		Oxidation catalyst	No

Hyperion identified in the application that the oxidation catalyst was not technically feasible because of the sporadic operating times of the units and stable, minimum temperatures, needed for the systems. This left only one BACT option which is good combustion practices. Table 7-106, identifies Hyperion's proposed control option, the rank of the control option, and the proposed emission limit.

Table 7-106 – Proposed Carbon Monoxide BACT Control and Limit for Startup Burners

Unit	Description	Proposed Control	Rank	Proposed Limit
#51 through #58	Gasifier startup burners	Good combustion practices	#1	Work practice requirements, no limit proposed

Based on DENR's review, there are no facilities with equivalent or more stringent limitations than those proposed by Hyperion for the proposed controls. For example, a review of Kentucky Department of Environmental Protection permit to Cash Creek Generation facility issued on January 17, 2008, for the integrated gasification combined cycle system does not note an emission limit (page 13 and 14). A review of Illinois EPA's permit to Christian County Generation facility issued on June 5, 2007, for the integrated gasification combined cycle notes the emission rate of 0.037 pounds per million Btus (page 63). This emission limit is for a boiler, which uses indirect heat. The emission limit would not be representative of a startup burner that uses direct heat.

DENR agrees that good combustion practices are the appropriate control technology choice to represent BACT for gasifier startup burners. Hyperion proposed a work practice standard as BACT that would be based on good combustion practices. In the application, Hyperion describes the amount of time the gasifier startup burners would operate. In each scenario the gasifier startup burners would operate equal to or more than eight hours at a time. A performance test could be conducted during this time period, which would not be due to startup, shutdown, or malfunction of the gasifier startup burner. DENR will establish a carbon monoxide emission limit for each gasifier startup burner. DENR is proposing a BACT emission limit for carbon monoxide of 0.37 pounds per million Btus, excluding startups, shutdowns, and malfunctions of the gasifier startup burner. The proposed limit is based on the emission rates used in the modeling and/or calculations. Compliance with the BACT emission limit for carbon monoxide shall be based on an average of three test runs based on a performance test.

The BACT emission limit for carbon monoxide is not applicable during periods of startup, shutdown, or malfunctions. The BACT emission limit for carbon monoxide during these occurrences will be discussed later.

7.1.5.6 Carbon Monoxide BACT for Generators and Fire Pumps

Hyperion identified in its application several options for BACT and identified which options were considered feasible or infeasible. Table 7-107 identifies the BACT options reviewed for generators and fire pumps, and if the options were considered feasible to install. DENR agreed with the first two steps of the BACT analysis.

Table 7-107 – Carbon Monoxide Options and Feasibility for Generators and Fire Pumps

Unit	Description	BACT Options	Feasible Options
#65 through #70	Emergency generators and fire pumps	NOx adsorb technology in conjunction with catalyzed diesel particulate filters	Yes
		SCR used in conjunction with oxidation catalyst	Yes
		Injection timing retard and exhaust gas recirculation	Yes

Table 7-108 identifies the feasible options, the estimated control efficiency by DENR, and the rank for each feasible option.

Table 7-108 – Top Carbon Monoxide Control Options for Generators and Fire Pumps

Unit	Description	BACT Options	Control Efficiency	Rank
#65 through #70	Emergency generators and fire pumps	NOx adsorb technology in conjunction with catalyzed diesel particulate filters	90% [1]	#1
		SCR used in conjunction with oxidation catalyst	80% [1]	#2
		Injection timing retard and exhaust gas recirculation	50 to 90% [2]	#3

[1] – The emission estimates were derived from the federal register notice of the proposed rules for New Source Performance Standard Subpart IIII (Vol. 71, No. 112 / Monday June 12, 2006); and
[2] –Memorandum from Tanya Parise. Alpha Gamma Technologies, Incorporated to Jaime Pagan, EPA Energy Strategies Group, dated December 18, 2007, Cost Impacts and Emission Reductions Associated with Final NSPS for Stationary SI ICE and NESHAP for Stationary RICE.

Hyperion proposed option #3 in the application based on the size of the unit, low emission rates, and the units only operate intermittently. Table 7-109, identifies Hyperion's proposed control option, the rank of the control option, and the proposed emission limit.

Table 7-109 – Proposed Carbon Monoxide BACT Control and Limit for Generators/Fire Pumps

Unit	Description	Proposed Control	Rank	Proposed Limit
#65 through #70	Emergency generators and fire pumps	Injection timing retard and exhaust gas recirculation	#3	New Source Performance Standard Subpart IIII requirement – 3.5 grams per kilowatt -hour

Based on DENR's review, there is one facility with equivalent or more stringent limitations than those proposed by Hyperion for the proposed controls. DENR reviewed each of these to verify the BACT emission limit.

A review of Arizona Department of Environmental Quality's technical review for the permit for the Arizona Clean Fuels Yuma Refinery issued on September 18, 2006, notes that the emission limit was 3.5 grams per kilowatt hour for similar size generators and fire pumps (page 441).

DENR agrees with the BACT analysis. However, Hyperion analysis alludes that a 2007 model engine could be purchased which would have higher emission rates than those required for a 2008 model year engine or greater. Hyperion will be able to purchase a 2008 model engine or greater once the permit is issued. Therefore, DENR recommends the BACT be the New Source Performance Standard requirements and require 2008 or new model engine shall be purchased and operated.

7.1.5.7 Carbon Monoxide BACT for Refinery and Gasification Flares

Due to the proposed control equipment, a BACT analysis for carbon monoxide was conducted for the refinery flares. In addition, a BACT analysis was conducted for the gasification flare, which will be used for the safe disposal of off-specification syngas that is produced during unit startups, shutdowns and malfunctions and that cannot be routed to the combined cycle combustion turbines, the pressure swing adsorption unit, or to another gasifier.

Hyperion identified in its application several options for BACT and identified which options were considered feasible or infeasible. Table 7-110 identifies the BACT options reviewed for refinery flares and gasification flare, and if the options were considered feasible to install. DENR agreed with the first two steps of the BACT analysis.

Table 7-110 – Carbon Monoxide Options and Feasibility for Refinery and Gasification Flares

Unit	Description	BACT Options	Feasible Options
#36 through #40 and #50	Refinery and gasification flares	Good combustion practices and flare minimization plan	Yes
		Oxidation catalyst	No

In the application, Hyperion states that the inherent design of the emergency flares with wide variety of operational conditions, open flame on a tall stack do not allow for the use of add-on control devices. That leaves only one feasible option, which is good combustion practices and a flare minimization plan. Table 7-111, identifies Hyperion's proposed control option, the rank of the control option, and the proposed emission limit.

Table 7-111 – Proposed Carbon Monoxide BACT Control and Limit for Flares

Unit	Description	Proposed Control	Rank	Proposed Limit
#36 through #40 and #50	Refinery and gasification flares	Flare minimization plan and design specifications	#1	Work practice requirements and design requirements in 40 CFR §60.18, no proposed limit

Based on DENR's review, there is one facility and two state rules with an equivalent or more stringent limitation than those proposed by Hyperion for the proposed controls. DENR reviewed each of these to verify the BACT emission limit.

A review of California's South Coast Air Management District's Rule 1118 – Control of Emissions from Refinery Flares amended November 4, 2005, specifies a work practice and design requirement for the operations of the flares (pages 1118-5 through 1118-7). The rule does not specify a numerical limit for flares.

A review of California's Bay Area Air Quality Management District's Regulation 12 Rule 11 – Flare Monitoring at Petroleum Refineries and Regulation 12 Rule 12 – Flares at Petroleum Refineries, specifies a work practice and design requirement for the operations of the flares (12-12-3). The rule does not specify a numerical limit for flares.

A review of Arizona Department of Environmental Quality's permit for the Arizona Clean Fuels Yuma Refinery issued on September 18, 2006, specifies a work practice and design requirements for the operations of the flares (page 401 through 407).

DENR's review indicates that good combustion practices and a flare minimization plan is the appropriate control technology choice for carbon monoxide to represent BACT for refinery and gasification flares. The operations of a flare are not conducive to conduct a performance test. Therefore, DENR agrees with Hyperion that a numerical carbon monoxide emission limit is not feasible to implement.

7.1.5.8 Carbon Monoxide BACT for Wastewater Treatment Plant

The technology chosen in Hyperion's BACT analysis for the wastewater treatment plant resulted in a BACT analysis for carbon monoxide emissions. Hyperion identified in its application several options for BACT and identified which options were considered feasible or infeasible. Table 7-112 identifies the BACT options reviewed for the wastewater treatment facility, and if the options were considered feasible to install.   DENR agreed with the first two steps of the BACT analysis.

Table 7-112 – Carbon Monoxide Options and Feasibility for Wastewater Treatment Plant

Unit	Description	BACT Options	Feasible Options
#45	Wastewater treatment's thermal oxidizer	Good combustion practices	Yes
		No controls (e.g. no thermal oxidizer)	No

The no control options would not be environmental beneficial since controlling the volatile organic compounds emissions outweighs the increase in carbon monoxide emissions generated from the thermal oxidizer. Therefore, the no control option was considered an infeasible option.

There is only one option, which is good combustion practice. Table 7-113, identifies Hyperion's proposed control option, the rank of the control option, and the proposed emission limit.

Table 7-113 – Proposed Carbon Monoxide BACT Control and Limit for Wastewater Treatment Plant

Unit	Description	Proposed Control	Rank	Proposed Limit
#45	Wastewater treatment's thermal oxidizer	Good combustion practices	#1	No proposed emission limit

Based on DENR's review, there is no facility with equivalent or more stringent limitations than those proposed by Hyperion for the proposed controls. For example, a review of Arizona Department of Environmental Quality's permit for the Arizona Clean Fuels Yuma Refinery issued on September 18, 2006, does not establish an emission limit for nitrogen oxide (page 347 through 351).

DENR agrees with good combustion practices for carbon monoxide emissions from the thermal oxidizer. DENR disagrees that there should be no emission limit for the thermal oxidizer. DENR proposes an emission limit of 0.08 pounds per million Btus, which equates to the emission rate for the thermal oxidizers for the sulfur recovery plant. DENR proposes compliance be demonstrated by a 3-hour average based on a stack performance test.

The BACT emission limit for carbon monoxide is not applicable during periods of startup, shutdown, or malfunctions. The BACT carbon monoxide emission limit during these occurrences will be discussed later.

7.1.5.9 Carbon Monoxide BACT for Coke Drum Steam Vents

After the coking process is completed, the coke drums are steamed out and cooled. Once the cooling process has completed, the coke drum is depressurized to the atmosphere through a steam vent. Hyperion conducted a BACT analysis during the periods when the coke drum is depressurized to the atmosphere.

Hyperion identified in its application several options for BACT and identified which options were considered feasible or infeasible. Table 7-114 identifies the BACT options reviewed for the coke steam vents, and if the options were considered feasible to install.   DENR agreed with the first two steps of the BACT analysis.

Table 7-114 – Carbon Monoxide Options and Feasibility for Coke Drum Steam Vents

Unit	Description	BACT Options	Feasible Options
#34 and #35	Coke drum steam vents	Design requirement of 2 pounds per square inch, gauged	No
		Design requirement of 5 pounds per square inch, gauged	Yes

Hyperion notes that EPA recently made a determination in the preamble to 40 CFR Part 60, Subpart Ja that it is technically infeasible to recover the coke drum blow down vapors at a drum pressure less than 5 pounds per square inch, gauged. In the application, Hyperion did not rank the BACT options in this case since there is only one feasible option. Since there is only one option, the design requirement of 5 pounds per square inch, gauged, is the top carbon monoxide control option for the coke drum steam vents.

Table 7-115, identifies Hyperion's proposed control option, the rank of the control option, and the proposed emission limit.

Table 7-115 – Proposed Carbon Monoxide BACT Control and Limit for Coke Drum Steam Vents

Unit	Description	Proposed Control	Rank	Proposed Limit
#34 and #35	Coke drum steam vents	Design requirement of 5 pounds per square inch, gauged	#1	Work design practice standards in accordance with 40 CFR Part 60, Subpart Ja

Based on DENR's review, there is no facility with equivalent or more stringent limitations than those proposed by Hyperion for the proposed controls. For example, a review of Arizona Department of Environmental Quality's permit for the Arizona Clean Fuels Yuma Refinery issued on September 18, 2006, does not establish an emission limit.

DENR's review indicates that the design requirement that each coke drum be depressurized to 5 pounds per square inch, gauged, before the exhaust gases can be vented to atmosphere is the appropriate control technology choice for carbon monoxide to represent BACT for a coke drum steam vents. DENR agrees with Hyperion that the proposed BACT carbon monoxide emission limit should be based on the work practice standards outlined in 40 CFR Part 60, Subpart Ja.

7.1.5.10 Carbon Monoxide BACT for Tank Farm Thermal Oxidizer

Hyperion conducted a BACT analysis for the Tank Farm for volatile organic compounds. DENR disagreed that a thermal oxidizer was not considered BACT for controlling most of the storage tanks. Due to the control technology recommended by DENR, DENR also conducted a BACT review for carbon monoxide.

DENR based its review on Hyperion's BACT analysis for the thermal oxidizers for the sulfur recovery plant, which resulted in the use of good combustion practices. Based on DENR's review, there is no facility with equivalent or more stringent limitations than those proposed by Hyperion for the proposed controls. For example, a review of Arizona Department of Environmental Quality's permit for the Arizona Clean Fuels Yuma Refinery issued on September 18, 2006, does not establish an emission limit (page 260 through 266).

DENR proposes the same emission limit of 0.08 pounds per million Btus as required for the sulfur recovery plant's thermal oxidizer. DENR is proposing demonstrating compliance by a 3-hour average based on a stack performance test.

The BACT emission limit for carbon monoxide is not applicable during periods of startup, shutdown, or malfunctions. The BACT carbon monoxide emission limit during these occurrences will be discussed later.

7.1.5.11 Carbon Monoxide BACT for Carbon Dioxide Vent

Hyperion is installing a Rectisol® wash process for the removal of acid gases (hydrogen sulfide, carbonyl sulfides, and carbon dioxide) from the shifted syngas. This process will emit carbon monoxide through the carbon dioxide vent. Hyperion conducted a BACT analysis for the carbon dioxide vent for carbon monoxide.

Hyperion identified in its application several options for BACT and identified which options were considered feasible or infeasible. Table 7-116 identifies the BACT options reviewed for the carbon dioxide vent and if the options were considered feasible to install. DENR agreed with the first two steps of the BACT analysis.

Table 7-116 – Carbon Monoxide Options and Feasibility for Carbon Dioxide Vent

Unit	Description	BACT Options	Feasible Options
#59	Carbon dioxide vent	Proper equipment design and operation	Yes
		Thermal oxidation	Yes
		Catalytic oxidation	Yes

Hyperion indicated in the application that the carbon monoxide emission rate from the Rectisol® wash process is sufficiently low that no further quantifiable emission reductions would be achieved by apply thermal oxidation or catalytic oxidation. Table 7-117 identifies Hyperion's proposed control option and emission limit.

Table 7-117 – Proposed Carbon Monoxide BACT Control and Limit for Carbon Dioxide Vent

Unit	Description	Proposed Control	Proposed Limit
#59	Carbon dioxide vent	Proper equipment design and operation	20 parts per million by volume [1,2]; and 25.1 pounds per hour [1,2]

[1] – Compliance based on a 24-hour rolling average, excluding periods of startup, shutdown, and malfunctions; and

[2] – Compliance based on a 365-day rolling average, including periods of startup, shutdown, and malfunctions.

Based on DENR's review, there are no facilities with equivalent or more stringent limitations than those proposed by Hyperion for the proposed controls. For example, a review of Kentucky Department of Environmental Protection permit to Cash Creek Generation facility issued on January 17, 2008, used a Selexol™ system for acid gas removal. The Selexol solution, which is enriched with hydrogen sulfide, is transferred to the sulfur recovery plant. The permit does not indicate a separate emission vent for the Selexol process.

A review of Illinois EPA's permit to Christian County Generation facility issued on June 5, 2007, used a Selexol™ system for acid gas removal. The Selexol solution, which is enriched with hydrogen sulfide, is transferred to the sulfur recovery plant. The permit does not indicate a separate emission vent for the Selexol process.

DENR agrees that proper equipment design and operation of the Rectisol® wash process is the appropriate control technology choice to represent BACT for carbon monoxide. DENR also agrees with the method of demonstrating compliance.

7.1.6 BACT Analysis for Sulfuric Acid Mist

7.1.6.1 Sulfuric Acid Mist BACT for Process Heaters

Hyperion noted that the BACT analysis for sulfur dioxide would be the same for sulfuric acid mist. DENR agrees with this conclusion. Therefore, DENR considers the sulfur dioxide BACT review representative of the sulfuric acid mist review.

7.1.6.2 Sulfuric Acid Mist BACT for Catalyst Regenerators

Hyperion did not identify an emission estimate for sulfuric acid mist for the catalyst regenerators. Due the very low emission rates of sulfur dioxide, DENR agrees that the emission of sulfuric acid mist is not generated or is negligible and does not require a BACT analysis.

7.1.6.3 Sulfuric Acid Mist BACT for Sulfur Recovery Plant

Hyperion noted that the BACT analysis for sulfur dioxide would be the same for sulfuric acid mist. DENR agrees with this conclusion. Therefore, DENR considers the sulfur dioxide BACT review representative of the sulfuric acid mist review.

7.1.6.4 Sulfuric Acid Mist BACT for IGCC Combustion Turbines

Hyperion noted that the BACT analysis for sulfur dioxide would be the same for sulfuric acid mist. DENR agrees with this conclusion. Therefore, DENR considers the sulfur dioxide BACT review representative of the sulfuric acid mist review.

7.1.6.5 Sulfuric Acid Mist BACT for IGCC Startup Burners

Hyperion noted that the BACT analysis for sulfur dioxide would be the same for sulfuric acid mist. DENR agrees with this conclusion. Therefore, DENR considers the sulfur dioxide BACT review representative of the sulfuric acid mist review.

7.1.6.6 Sulfuric Acid Mist BACT for Refinery and Gasification Flares

Hyperion did not conduct a BACT analysis for sulfuric acid mist for the refinery and gasification flares. The formation of sulfuric acid mist is dependent upon the conversion of the sulfur in the gas stream prior to being flared as sulfur dioxide in the exhaust gas. Therefore DENR considers the sulfur dioxide BACT review representative of the sulfuric acid mist review.

7.1.7 BACT Analysis for Hydrogen Sulfide

7.1.7.1 Hydrogen Sulfide BACT for Sulfur Recovery Plant

The air emissions from the sulfur recovery plant will be controlled by six thermal oxidizers (Unit #42a, #42b, #42c, #42d, 42e, and 42f). Hyperion is proposing to operate a maximum of four thermal oxidizers at one time. As such, a minimum of two thermal oxidizers are being installed as a backup.

Hyperion identified in its application several options for BACT and identified which options were considered feasible or infeasible. Table 7-118 identifies the BACT options reviewed for the sulfur recovery plant and if the options were considered feasible to install. DENR agreed with the first two steps of the BACT analysis.

Table 7-118 – Hydrogen Sulfide Options and Feasibility for Sulfur Recovery Plant

Unit	Description	BACT Options	Feasible Options
#42	Sulfur recovery plant's thermal oxidizers	Claus reactor	Yes
		Claus reactor and tail gas treater	Yes
		Claus reactor and thermal oxidizer	Yes
		Claus reactor, tail gas treater, and thermal oxidizer	Yes
		Claus reactor, thermal oxidizer, and wet scrubber	Yes

In the application, Hyperion ranked the feasible control options based on the control efficiency of the option, which is displayed in Table 7-119.

Table 7-119 – Top Hydrogen Sulfide Control Options for Sulfur Recovery Plant

Unit	Description	Feasible Options	Control Efficiency	Rank
#42	Sulfur recovery plant's thermal oxidizers	Claus reactor, tail gas treater, and thermal oxidizer	99.97%	#2
		Claus reactor, thermal oxidizer, and wet scrubber	99.94%	#3
		Claus reactor and tail gas treater	99%	#4
		Claus reactor and thermal oxidizer	99%	
		Claus Reactor	98%	#5

Table 7-120 identifies Hyperion's proposed control option, the rank of the control option, and the proposed emission limit.

Table 7-120 – Proposed Hydrogen Sulfide BACT Control and Limit for Sulfur Recovery Plant

Unit	Description	Proposed Control	Rank	Proposed Limit
#42	Sulfur recovery plant's thermal oxidizers	Claus reactor, tail gas treater, and thermal oxidizer	#1	A combined 0.3 pounds per hour for the system

Based on DENR's review, there are two facilities with equivalent or more stringent limitations than those proposed by Hyperion for the proposed controls. DENR reviewed each of these to verify the BACT emission limit.

A review of Arizona Department of Environmental Quality's technical review for the permit for the Arizona Clean Fuels Yuma Refinery issued on September 18, 2006, notes that the emission limit hydrogen sulfide is 0.089 pounds per hour at a sulfur load to the system of 608 long tons per day. The total sulfur removal efficiency is 99.97% (page 181).

A review of Louisiana Department of Environmental Quality's permit for Marathon Petroleum Company's Garyville Refinery issued on December 27, 2006, notes that the emission limit for sulfur dioxide, which also minimizes hydrogen sulfide was 56.86 pounds per hour. The total sulfur removal efficiency is 99.95%. (page 11 and 15).

The sulfur dioxide emissions are generated in the process to control hydrogen sulfide emissions. DENR agrees that controlling the hydrogen sulfide emissions outweighs the impact of generating sulfur dioxide from the process. Therefore, DENR agrees best control option is not BACT.

DENR's review indicates that the Claus reactor, tail gas treater, and thermal oxidizer is the appropriate control technology choice for hydrogen sulfide to represent BACT for the sulfur recovery plant. DENR agrees with the hydrogen sulfide BACT emission limit and the method of compliance identified in Table 7-120 for each thermal oxidizer associated with the sulfur recover plant. DENR is also recommending a 0.00015 pounds per long ton limit to ensure that each thermal oxidizer system is operated properly. The 0.3 pounds per hour limit was divided by the maximum sulfur loading of 2,040 long tons per hour to convert the emission limit to pounds per long ton sulfur. This limit will apply to each thermal oxidizer separately and not a combined limit. Compliance is based on a 3-hour average performance test.

7.1.7.2 Hydrogen Sulfide BACT for Refinery and Gasification Flares

Hyperion noted that the BACT analysis for volatile organic compounds be the same for hydrogen sulfide. DENR agrees with this conclusion. DENR considers the volatile organic compound BACT review representative of the hydrogen sulfide review.

7.1.7.3 Hydrogen Sulfide BACT for Carbon Dioxide Vent

Hyperion is installing a Rectisol® wash process for the removal of acid gases (hydrogen sulfide, carbonyl sulfides, and carbon dioxide) from the shifted syngas. This process will emit hydrogen sulfide through the carbon dioxide vent. Hyperion conducted a BACT analysis for the carbon dioxide vent for hydrogen sulfide.

Hyperion identified in its application several options for BACT and identified which options were considered feasible or infeasible. Table 7-121 identifies the BACT options reviewed for the carbon dioxide vent and if the options were considered feasible to install. DENR agreed with the first two steps of the BACT analysis.

Table 7-121 – Hydrogen Sulfide Options and Feasibility for Carbon Dioxide Vent

Unit	Description	BACT Options	Feasible Options
#59	Carbon dioxide vent	Proper equipment design and operation	Yes
		Thermal oxidation	Yes
		Catalytic oxidation	Yes

Hyperion indicated that the hydrogen sulfide emission rate from the Rectisol® wash process is sufficiently low that no further quantifiable emission reductions would be achieved by apply thermal oxidation or catalytic oxidation. Table 7-122 identifies Hyperion's proposed control option and emission limit.

Table 7-122 – Proposed Hydrogen Sulfide BACT Control and Limit for Carbon Dioxide Vent

Unit	Description	Proposed Control	Proposed Limit
#59	Carbon dioxide vent	Proper equipment design and operation	3 parts per million by volume [1]; and 4.2 pounds per hour [2]

[1] – Compliance based on a 24-hour rolling average, excluding periods of startup, shutdown, and malfunctions; and

[2] – Compliance based on a 365-day rolling average, including periods of startup, shutdown, and malfunctions.

Based on DENR's review, there are no facilities with equivalent or more stringent limitations than those proposed by Hyperion for the proposed controls. For example, a review of Kentucky

Department of Environmental Protection permit to Cash Creek Generation facility issued on January 17, 2008, used a Selexol™ system for acid gas removal. The Selexol solution, which is enriched with hydrogen sulfide, is transferred to the sulfur recovery plant. The permit does not indicate a separate emission vent for the Selexol process.

A review of Illinois EPA's permit to Christian County Generation facility issued on June 5, 2007, used a Selexol™ system for acid gas removal. The Selexol solution, which is enriched with hydrogen sulfide, is transferred to the sulfur recovery plant. The permit does not indicate a separate emission vent for the Selexol process.

DENR agrees that proper equipment design and operation of the Rectisol® wash process is the appropriate control technology choice to represent BACT for hydrogen sulfide and the method of demonstrating compliance.

7.1.8 BACT Analysis for Startup, Shutdown, and Malfunctions

To demonstrate compliance with BACT emission limits noted above, DENR has specified the method for demonstrating compliance using continuous emission monitoring systems, performance tests, etc. For units and pollutants in which compliance with a BACT emission limit is based on continuous emission monitoring equipment, the BACT emission limit includes periods of startup, shutdown, and malfunctions unless otherwise specified in the section. For those units and pollutants that compliance is not based on a continuous emission monitoring system, a performance test has been required to demonstrate compliance with the BACT emission limits during representative conditions. Startup, shutdown, and malfunctions are not considered representative conditions to conduct a performance test.

Startup and shutdown processes for some equipment do not occur over a long enough period of time to complete a valid performance test. Other problems, such as the cost, technological issues, etc. also occur when trying to recreate a malfunction to attempt to conduct a performance test. DENR does not believe it is prudent to require a source to replicate a malfunction to conduct a performance test to demonstrate compliance with a technology based emission limit.

As noted in ARSD 74:36:11:01, all stack performance tests must be conducted in accordance with the applicable method specified in 40 CFR § 60.17; 40 CFR Part 60, Appendix A; 40 CFR § 63.14; 40 CFR Part 63, Appendix A; and 40 CFR Part 51, Appendix M. These performance methods do not specify the conditions at which the facility must operate. However, the facility parameters under 40 CFR Part 60 and 40 CFR Part 63 at which these performance tests should be conducted are listed under 40 CFR § 60.8(c) and 40 CFR § 63.7(e). The regulations require that performance testing be conducted during representative operations and that startup, shutdown, and malfunctions are not considered representative operations. This ensures that performance tests are conducted while a unit is operating in a mode that is representative of typical operations.

Since a performance test is not conducive to be conducted during a startup, shutdown, malfunction period, DENR does not believe it is prudent to establish a numerical BACT limit where compliance cannot be verified. This is not an issue with the use of a continuous emission monitoring system that is able to record emissions during a startup, shutdown, or malfunction.

The Clean Air Act 302(k) identifies an emission limit and emission standard as a requirement, which limits the quantity, rate, or concentration of emissions of air pollutants on a continuous basis, including any requirement relating to the operation or maintenance of a source to assure continuous emission reduction, and any design, equipment, work practice or operational standard. The PSD rules at 40 CFR § 52.21(b)(12) establishes that, if the permitting agency determines that technological or economic limitations on the application of measurement methodology to a particular emissions unit would make the imposition of an emissions standard infeasible, a design, equipment, work practice, operational standard, or combination thereof, may be prescribed instead to satisfy the requirement for the application of BACT.

As such, an alternative method or standard will be used to demonstrate compliance during periods of startup, shutdown, and malfunctions that use a performance test to demonstrate compliance. The permit will require a startup, shutdown, and malfunction plan as BACT for these time periods.

Due to logistics of conducting performance tests there is limited data to determine the actual emission reductions. In concept, the emission reductions would be similar for those pre-process or pre-combustion type controls. For example, for sources that limit the amount of sulfur in the refinery gas would meet the BACT emission limits established for sulfur dioxide during normal operations (e.g. non startup, shutdown, or malfunctions).

The use of the post-combustion controls is a requirement even during startup, shutdown, and malfunctions of the operations. These controls are not optimized for these periods but during normal operations, which generally constitutes a majority of the operationally time. Even during these periods, there will be some emission reductions. The highest emission rates in pounds per hour are expected to occur at the maximum operational rates. Hyperion would likely meet the BACT emission limit in pounds per hour because startup and shutdown periods occur at low operational loads.

7.2 Air Quality Analysis

The air quality analysis must satisfy the following three criteria before the construction of a major source or major modification to a major source under the PSD program can be approved:

1. The air quality analysis must determine if the PSD de minimis monitoring levels are triggered, which would require preconstruction ambient air quality monitoring or use ambient monitoring data that is representative of the proposed location;

2. The air quality analysis must demonstrate that the BACT emission limits from the proposed project added with the background concentrations for each pollutant will not cause a violation of any applicable National Ambient Air Quality Standards (NAAQS); and
3. The BACT emission limits from the proposed project do not exceed any applicable PSD Class I or II increments.

For the air quality analysis, Hyperion performed an air dispersion modeling analysis using the AERMOD model (Version 07026) with regulatory defaults. The AERMOD model is an EPA-approved, steady state, air dispersion model that is designed to estimate downwind concentrations from single or multiple industrial sources. Surface air meteorological data from Sioux Falls, SD (#14944) and upper air data from NWS Omaha, Nebraska (#94980) from 2000 to 2004 were incorporated into the analysis.

Table 7-123 lists the onsite units, stack locations and stack parameters that were modeled. The parameters are based on North American Datum (NAD) 83 and Universal Transverse Mercator zone (UTM) 14. Several offsite sources were included to determine the cumulative impacts on the National Ambient Air Quality Standards and PSD Increments.

Table 7-123 – Project Modeled Parameters

Unit	Description	Modeled ID	Modeled Description	Northing (Meters)	Easting (Meters)	Stack Height Feet (ft)	Exit Temp (F)	Exit Velocity (ft/s)	Stack Diameter Feet (ft)
#1	Atmospheric crude charge heater #1	U1CRDH	Crude Charge Heater #1	686266.88	4742708.00	175	426	21.2	13.0
#2	Atmospheric crude charge heater #2	U2CRDH	Crude Charge Heater #2	686521.00	4742715.00	175	426	21.2	13.0
#3	Vacuum charge heater #1	U1VACH	Vacuum Charge Heater #1	686195.81	4742709.00	175	426	22.7	8.0
#4	Vacuum charge heater #2	U2VACH	Vacuum Charge Heater #2	686448.56	4742715.00	175	426	22.7	8.0
#5	Naphtha hydrotreater charge heater	U6CRGH	Naphtha Hydrotreater Charge Heater	686332.94	4742316.50	175	460	21.9	8.0
#6	Naphtha hydrotreater stripper reboiler heater	U6SRBH	Naphtha Hydrotreater Stripper Reboiler Heater	686319.50	4742316.50	175	460	24.2	7.0
#7	Naphtha splitter reboiler heater	U6STRH	Naphtha Splitter Reboiler Heater	686305.38	4742316.50	175	460	21.4	9.0
#8	Distillate hydrotreater feed heater	U7CRGH	Distillate Hydrotreater Feed Heater	686426.88	4742313.00	175	426	26.4	6.0

Unit	Description	Modeled ID	Modeled Description	Northing (Meters)	Easting (Meters)	Stack Height Feet (ft)	Exit Temp (F)	Exit Velocity (ft/s)	Stack Diameter Feet (ft)
#9	Delayed coker #1A heater	U8COKH1	Delayed Coker #1A Heater	686428.13	4741873.00	220	426	20.3	9.0
#10	Delayed coker #1B heater	U9COKH1	Delayed Coker #1B Heater	686428.69	4741896.00	220	426	20.3	9.0
#11	Delayed coker #2A heater	U8COKH2	Delayed Coker #2A Heater	686429.88	4741675.00	220	426	20.3	9.0
#12	Delayed coker #2B heater	U9COKH2	Delayed Coker #2B Heater	686429.31	4741698.50	220	426	20.3	9.0
#13	Number one platformer charge and interheater #1	U13CRGH1	CCR Platforming Unit 1	686336.81	4742516.50	150	426	24.7	15.0
#14	Number one platformer interheater #2 and #3	U14CRGH1	CCR Platforming Unit 2	686357.00	4742517.00	150	426	24.7	15.0
#15	Number two platformer charge and interheater #1	U13CRGH2	CCR Platforming No. 2 Unit 1	686513.63	4742521.50	150	426	23.1	12.0
#16	Number two platformer interheater #2 and #3	U14CRGH2	CCR Platforming No. 2 Unit 2	686536.88	4742521.50	150	426	23.1	12.0
#17	Oleflex heater	U20CRGH	Oleflex Heater	686609.63	4742305.50	200	539	20.5	15.0
#18	Reformate splitter reboiler	U13RSRH	CCR Reformate	686293.69	4742520.50	150	802	20.7	8.0

Unit	Description	Modeled ID	Modeled Description	Northing (Meters)	Easting (Meters)	Stack Height Feet (ft)	Exit Temp (F)	Exit Velocity (ft/s)	Stack Diameter Feet (ft)
			Splitter						
#19	Number one hydrocracker fractionator feed heater	U17FFH	Hydrocracker Frac Section Heater 1	686737.69	4742694.50	200	532	21.6	16.0
#20	Number two hydrocracker fractionator feed heater	U18FFH	Hydrocracker Frac Section Heater 2	686909.94	4742699.00	200	532	21.6	16.0
#21	Number one hydrocracker heater #1A	U17S1H1	Hydrocracker Stage 1 Heater Trn 1-1	686739.63	4742618.00	200	650	21.8	5.0
#22	Number one hydrocracker heater #1B	U18S1H1	Hydrocracker Stage 1 Heater Trn 1-2	686912.13	4742623.00	200	650	21.8	5.0
#23	Number one hydrocracker heater #1C	U17S1H2	Hydrocracker Stage 1 Heater Trn 2-1	686729.44	4742618.00	200	650	21.8	5.0
#24	Number one hydrocracker heater #2A	U18S1H2	Hydrocracker Stage 1 Heater Trn 2-2	686903.25	474623.00	200	650	21.8	5.0
#25	Number one hydrocracker heater #2B	U17S1H3	Hydrocracker Stage 1 Heater Trn 3-1	686718.00	4742618.00	200	650	21.8	5.0
#26	Number two hydrocracker	U18S1H3	Hydrocracker	686892.75	4742623.00	200	650	21.8	5.0

Unit	Description	Modeled ID	Modeled Description	Northing (Meters)	Easting (Meters)	Stack Height Feet (ft)	Exit Temp (F)	Exit Velocity (ft/s)	Stack Diameter Feet (ft)
	heater #1A		Stage 1 Heater Trn 3-2						
#27	Number two hydrocracker heater #1B	U17S2H1	Hydrocracker Stage 2 Heater Trn 1-1	686706.50	4742618.00	200	474	27.8	4.0
#28	Number two hydrocracker heater #1C	U18S2H1	Hydrocracker Stage 2 Heater Trn 1-2	686880.94	4742623.00	200	474	27.8	4.0
#29	Number two hydrocracker heater #2A	U17S2H2	Hydrocracker Stage 2 Heater Trn 2-1	686695.69	4742618.00	200	474	27.8	4.0
#30	Number two hydrocracker heater #2B	U18S2H2	Hydrocracker Stage 2 Heater Trn 2-2	686870.75	4742623.00	200	474	27.8	4.0
#31	Number one platformer catalyst regenerator	U13REGN1	Reformer Regenerator Unit 1	686366.63	4742475.50	160	100	13.0	1.4
#32	Number two platformer catalyst regenerator	U13REGN2	Reformer Regenerator Unit 2	686546.56	4742481.00	160	100	13.0	1.4
#33	Oleflex catalyst regenerator	U20REGN	Oleflex Regenerator	686588.69	4742265.50	160	100	18.0	0.5
#34	Coke drum #1 – four steam	U89COKS	Coker Drum	686503.00	4741911.00	275	212	0.0	1.7

Unit	Description	Modeled ID	Modeled Description	Northing (Meters)	Easting (Meters)	Stack Height Feet (ft)	Exit Temp (F)	Exit Velocity (ft/s)	Stack Diameter Feet (ft)
	vents	V	Steam Vent						
#35	Coke drum #2 – four steam vents								
#36	Refinery flare #1	FLARE 1	Refinery Flare Pilot 1	687411.06	4742269.00	200	1983	0.6	5.0
#37	Refinery flare #2	FLARE 2	Refinery Flare Pilot 2	687417.19	4742108.50	200	1983	0.6	5.0
#38	Refinery flare #3	FLARE 3	Refinery Flare Pilot 3	687565.88	4742266.00	213	1983	0.6	5.0
#39	Refinery flare #4	FLARE 4	Refinery Flare Pilot 4	687571.00	4742105.00	213	1983	0.6	5.0
#40	Refinery flare #5	FLARE 5	Coker Flare	687571.00	4741845.16	213	1983	1.0	4.0
#41	Cooling tower (13 cells)	COOL1		687188.13	4742281.00	50	-460	22.0	35.0
		COOL2		687200.75	4742281.00				
		COOL3		687187.38	4742266.00				
		COOL4		687200.75	4742266.50				
		COOL5		687187.38	4742249.50				
		COOL6		687200.75	4742250.50				
		COOL7		687187.38	4742233.50				
		COOL8		687200.75	4742234.00				
		COOL9		687187.38	4742218.50				
		COOL10		687200.75	4742219.50				
		COOL11		687187.38	4742206.50				
		COOL12		687200.75	4742205.50				
		COOL13		687186.69	4742194.00				
	Sulfur Recover Plant.								
#42a	Thermal oxidizer #1	U26TO1	SRU TO 1	686423.31	4741961.50	100	525	23.4	6.0

Unit	Description	Modeled ID	Modeled Description	Northing (Meters)	Easting (Meters)	Stack Height Feet (ft)	Exit Temp (F)	Exit Velocity (ft/s)	Stack Diameter Feet (ft)
#42b	Thermal oxidizer #2	U26TO2	SRU TO 2	686461.13	4741961.50	100	525	23.4	6.0
#42c	Thermal oxidizer #3	U26TO3	SRU TO 3	686506.94	4741963.00	100	525	23.4	6.0
#42d	Thermal oxidizer #4	U26TO4	SRU TO 4	686543.81	4741963.00	100	525	23.4	6.0
#42e	Thermal oxidizer #5								
#42f	Thermal oxidizer #6								
#43	Railcar loading rack								
#44	Truck loading rack								
#45	Wastewater treatment plant - Thermal oxidizer	WWTP	Waste Water Treatment Oxidizer	687062.56	4742137.00	50	500	53.7	0.3
	Petroleum coke storage building								
#46a	Baghouse #1	COAL1	North FF-1	686560.88	4741874.00	115	100	50.96	5.0
#46b	Baghouse #2	COAL2	North FF-2	686559.88	4741810.00	115	100	50.96	5.0
#46c	Baghouse #3	COAL3	South FF-1	686561.94	4741694.00	115	100	50.96	5.0
#46d	Baghouse #4	COAL4	South FF-2	686562.94	4741610.00	115	100	50.96	5.0
#47	Coal/coke unloading building	COAL5	Rail Unloading Bldg	686652.00	4741525.00	40	80	47.2	3.0
#48	Flux unloading building	COAL6	Rail Unloading Bldg	686774.19	4741521.00	40	80	23.6	3.0
#49	Slag loading building	COAL7	Rail Unloading Bldg	686812.50	4741519.00	40	80	23.6	3.0
#50	Gasification system - Flare	IGCCFL1	Power lsland Flare Pilot	687172.69	4741886.00	213	1836	0.8	5.0

Unit	Description	Modeled ID	Modeled Description	Northing (Meters)	Easting (Meters)	Stack Height Feet (ft)	Exit Temp (F)	Exit Velocity (ft/s)	Stack Diamete r Feet (ft)
		IGCCFL2	Power Island Flare	687172.69	4741886.00	213	1832	508.8	5.0
#51	Gasifier startup burner #1	IGCCSV1	Power Island Startup Vent 1	686860.00	4741711.00	200	236	41.6	3.5
#52	Gasifier startup burner #2	IGCCSV2	Power Island Startup Vent 2	686874.00	4741711.00	200	236	41.6	3.5
#53	Gasifier startup burner #3	IGCCSV3	Power Island Startup Vent 3	686888.00	4741711.00	200	236	41.6	3.5
#54	Gasifier startup burner #4	IGCCSV4	Power Island Startup Vent 4	686902.00	4741711.00	200	236	41.6	3.5
#55	Gasifier startup burner #5	IGCCSV5	Power Island Startup Vent 5	686916.00	4741711.00	200	236	41.6	3.5
#56	Gasifier startup burner #6	IGCCSV6	Power Island Startup Vent 6	686930.00	4741711.00	200	236	41.6	3.5
#57	Gasifier startup burner #7								
#58	Gasifier startup burner #8								
#59	Power island acid gas removal system	IGCCAGR	Power Island Acid Gas Removal	687115.00	4741757.00	200	100	63.64	10.0
#60	Combined cycle gas turbine #1	IGCCCT1	Power lsland CT 1	686874.25	4741885.50	200	275	75.0	13.4
		IGCCDB1	Power lsland Duct Burner 1	686874.25	4741885.50	200	275	75.0	13.4
#61	Combined cycle gas turbine #2	IGCCCT2	Power lsland CT 2	686904.00	4741885.50	200	275	75.0	13.4
		IGCCDB2	Power lsland Duct Burner 2	686904.00	4741885.50	200	275	75.0	13.4

Unit	Description	Modeled ID	Modeled Description	Northing (Meters)	Easting (Meters)	Stack Height Feet (ft)	Exit Temp (F)	Exit Velocity (ft/s)	Stack Diameter Feet (ft)
#62	Combined cycle gas turbine #3	IGCCCT3	Power lsland CT 3	686933.75	4741885.50	200	275	75.0	13.4
		IGCCDB3	Power lsland Duct Burner 3	686933.75	4741885.50	200	275	75.0	13.4
#63	Combined cycle gas turbine #4	IGCCCT4	Power lsland CT 4	686962.88	4741885.50	200	275	75.0	13.4
		IGCCDB4	Power lsland Duct Burner 4	686962.88	4741885.50	200	275	75.0	13.4
#64	Combined cycle gas turbine #5								
#65	Emergency generator #1	GEN1	Emergency Generator No. 1	687063.00	4742365.00	25	950	109.0	1.0
#66	Emergency generator #2	GEN2	Emergency Generator No. 2	687088.00	4742365.00	25	950	109.0	1.0
#67	Emergency generator #3	GEN3	Emergency Generator No. 3	687113.00	4742365.00	25	950	109.0	1.0
#68	Emergency generator #4	GEN4	Emergency Generator No. 4	687138.00	4742365.00	25	950	109.0	1.0
#69	Fire water pump #1	FIREWP1	Fire Water Pump 1	684740.00	4741479.00	25	850	267.0	1.0
#70	Fire water pump #2	FIREWP2	Fire Water Pump 2	684770.00	4741479.00	25	850	267.0	1.0

The Hyperion project triggered a PSD review for particulate matter, sulfur dioxide, nitrogen oxide, volatile organic compounds, carbon monoxide, sulfuric acid mist and hydrogen sulfide. It should be noted that there is no NAAQS or PSD increment for sulfuric acid mist or hydrogen sulfide and there is no EPA approved model to model the impacts of volatile organic compounds (ozone). Table 7-124 summarizes the emission rates used in the modeling for the appropriate unit and pollutant.

Table 7-124 – Modeled Point Source Emission Rates (pounds per hour)

Modeled ID	Description	PM10	SO_2	NO_x	CO
U1CRDH	Crude Charge Heater #1	3.976	2.454	3.181	21.206
U2CRDH	Crude Charge Heater #2	3.976	2.454	3.181	21.206
U1VACH	Vacuum Charge Heater #1	1.610	0.994	1.288	8.586
U2VACH	Vacuum Charge Heater #2	1.610	0.994	1.288	8.586
U6CRGH	Naphtha Hydrotreater Charge Heater	1.497	0.924	1.198	7.984
U6SRBH	Naphtha Hydrotreater Stripper Reboiler Heater	1.266	0.781	1.013	6.751
U6STRH	Naphtha Splitter Reboiler Heater	1.851	1.143	1.481	9.874
U7CRGH	Distillate Hydrotreater Feed Heater	1.054	0.651	0.843	5.622
U8COKH1	Delayed Coker #1A Heater	1.818	1.122	1.455	9.698
U9COKH1	Delayed Coker #1B Heater	1.818	1.122	1.455	9.698
U8COKH2	Delayed Coker #2A Heater	1.818	1.122	1.455	9.698
U9COKH2	Delayed Coker #2B Heater	1.818	1.122	1.455	9.698
U89COKSV	Coker Drum Steam Vent	3.000	0.000	0.000	0.300
U13CRGH1	CCR Platforming Unit 1	6.184	3.817	4.947	32.981
U14CRGH1	CCR Platforming Unit 2	6.184	3.817	4.947	32.981
U13CRGH2	CCR Platforming No. 2 Unit 1	3.696	2.281	2.957	19.714
U14CRGH2	CCR Platforming No. 2 Unit 2	3.696	2.281	2.957	19.714
U13RSRH	CCR Reformate Splitter	1.035	0.639	0.828	5.520
U17S1H1	Hydrocracker Stage 1 Heater Trn 1-1	0.501	0.309	1.672	2.674
U18S1H1	Hydrocracker Stage 1 Heater Trn 1-2	0.501	0.309	1.672	2.674
U17S1H2	Hydrocracker Stage 1 Heater Trn 2-1	0.501	0.309	1.672	2.674
U18S1H2	Hydrocracker Stage 1 Heater Trn 2-2	0.501	0.309	1.672	2.674
U17S1H3	Hydrocracker Stage 1 Heater Trn 3-1	0.501	0.309	1.672	2.674

Modeled ID	Description	PM10	SO_2	NO_x	CO
U18S1H3	Hydrocracker Stage 1 Heater Trn 3-2	0.501	0.309	1.672	2.674
U17S2H1	Hydrocracker Stage 2 Heater Trn 1-1	0.487	0.300	1.623	2.596
U18S2H1	Hydrocracker Stage 2 Heater Trn 1-2	0.487	0.300	1.623	2.596
U17S2H2	Hydrocracker Stage 2 Heater Trn 2-1	0.487	0.300	1.623	2.596
U18S2H2	Hydrocracker Stage 2 Heater Trn 2-2	0.487	0.300	1.623	2.596
U17FFH	Hydrocracker Frac Section Heater 1	5.066	3.127	4.053	27.021
U18FFH	Hydrocracker Frac Section Heater 2	5.066	3.127	4.053	27.021
U20CRGH	Oleflex Heater	4.533	2.798	3.627	24.177
U26TO1	SRU TO 1	0.609	28.605	6.842	37.229
U26TO2	SRU TO 2	0.609	28.605	6.842	37.229
U26TO3	SRU TO 3	0.609	28.605	6.842	37.229
U26TO4	SRU TO 4	0.609	28.605	6.842	37.229
FLARE 1	Refinery Flare Pilot 1	0.006	0.005	0.068	0.370
FLARE 2	Refinery Flare Pilot 2	0.006	0.005	0.068	0.370
FLARE 3	Refinery Flare Pilot 3	0.006	0.005	0.068	0.370
FLARE 4	Refinery Flare Pilot 4	0.006	0.005	0.068	0.370
FLARE5	Coker Flare	0.006	0.005	0.068	0.370
IGCCCT1	Power lsland CT 1	21.362	1.533	22.159	6.423
IGCCCT2	Power lsland CT 2	21.362	1.533	22.159	6.423
IGCCCT3	Power lsland CT 3	21.362	1.533	22.159	6.423
IGCCCT4	Power lsland CT 4	21.362	1.533	22.159	6.423
IGCCDB1	Power lsland Duct Burner 1	15.540	4.457	7.676	4.672
IGCCDB2	Power lsland Duct Burner 2	15.540	4.457	7.676	4.672
IGCCDB3	Power lsland Duct Burner 3	15.540	4.457	7.676	4.672
IGCCDB4	Power lsland Duct Burner 4	15.540	4.457	7.676	4.672
IGCCSV1	Power Island Startup Vent 1	0.109	0.114	1.224	6.660
IGCCSV2	Power Island Startup Vent 2	0.109	0.114	1.224	6.660
IGCCSV3	Power Island Startup Vent 3	0.109	0.114	1.224	6.660
IGCCSV4	Power Island Startup Vent 4	0.109	0.114	1.224	6.660

Modeled ID	Description	PM10	SO_2	NO_x	CO
IGCCSV5	Power Island Startup Vent 5	0.109	0.114	1.224	6.660
IGCCSV6	Power Island Startup Vent 6	0.109	0.114	1.224	6.660
IGCCFL1	Power lsland Flare Pilot	0.022	0.006	0.068	0.370
IGCCFL2	Power Island Flare	4.762	15.729	53.477	290.980
IGCCAGR	Power Island Acid Gas Removal	0.000	0.000	0.000	2279.290
U13REGN1	Reformer Regenerator Unit 1	0.010	0.000	0.080	0.490
U13REGN2	Reformer Regenerator Unit 2	0.010	0.000	0.080	0.490
U20REGN	Oleflex Regenerator	0.002	0.000	0.015	0.089
WWTP	Waste Water Treatment Oxidizer	0.000	0.000	5.000	0.000
COAL1	North FF-1	2.425	0.000	0.000	0.000
COAL2	North FF-2	2.425	0.000	0.000	0.000
COAL3	South FF-1	2.425	0.000	0.000	0.000
COAL4	South FF-2	2.425	0.000	0.000	0.000
COAL5	Rail Unloading Bldg	0.838	0.000	0.000	0.000
COAL6	Rail Unloading Bldg	0.419	0.000	0.000	0.000
COAL7	Rail Unloading Bldg	0.419	0.000	0.000	0.000
COOL1	Cooling Tower Cell 1	0.094	0.000	0.000	0.000
COOL2	Cooling Tower Cell 2	0.094	0.000	0.000	0.000
COOL3	Cooling Tower Cell 3	0.094	0.000	0.000	0.000
COOL4	Cooling Tower Cell 4	0.094	0.000	0.000	0.000
COOL5	Cooling Tower Cell 5	0.094	0.000	0.000	0.000
COOL6	Cooling Tower Cell 6	0.094	0.000	0.000	0.000
COOL7	Cooling Tower Cell 7	0.094	0.000	0.000	0.000
COOL8	Cooling Tower Cell 8	0.094	0.000	0.000	0.000
COOL9	Cooling Tower Cell 9	0.094	0.000	0.000	0.000
COOL10	Cooling Tower Cell 10	0.094	0.000	0.000	0.000
COOL11	Cooling Tower Cell 11	0.094	0.000	0.000	0.000
COOL12	Cooling Tower Cell 12	0.094	0.000	0.000	0.000
COOL13	Cooling Tower Cell 13	0.094	0.000	0.000	0.000
FIREWP1	Fire Water Pump 1	0.992	0.037	0.248	17.361
FIREWP2	Fire Water Pump 2	0.992	0.037	0.248	17.361
GEN1	Emergency Generator No. 1	0.265	0.010	0.066	4.630
GEN2	Emergency Generator No. 2	0.265	0.010	0.066	4.630

Modeled ID	Description	PM10	SO_2	NO_x	CO
GEN3	Emergency Generator No. 3	0.265	0.010	0.066	4.630
GEN4	Emergency Generator No. 4	0.265	0.010	0.066	4.630

7.2.1 Deminimis Monitoring Levels

Preconstruction ambient monitoring is used to determine the background concentration prior to a new source or new modification is constructed. As allowed in 40 CFR §52.21(i)(8)(i), modeling of just the proposed project for the pollutants that triggered a PSD review may be conducted to determine if the proposed BACT emission limits would exceed the deminimis monitoring levels. If the deminimis monitoring levels are not exceeded, preconstruction ambient monitoring is not required. Table 7-125 compares the modeling results for particulate matter, sulfur dioxide, nitrogen oxide, and carbon monoxide to the significant impact levels to determine if preconstruction monitoring is required.

Table 7-125 – PSD Class II Significant Monitoring Impact Levels

Pollutant	Averaging Period	Hyperion Modeled Impact (ug/m^3)	Significant Monitoring Concentration (ug/m^3)	Monitoring Required
PM-10	24-hour	19.9	10	Yes
SO_2	24-hour	55.9	13	Yes
NOx	Annual	2.40	14	No
CO	8-hour	464	575	No

Based on the modeling analysis, the significant monitoring concentration levels were predicted to be exceeded due to emissions of sulfur dioxide and particulate matter 10 microns in diameter or less (PM10). DENR approved using existing ambient background pollutant data in lieu of site-specific preconstruction monitoring data in this modeling evaluation. The existing ambient monitoring data met the requirements for preconstruction ambient monitoring.

7.2.2 National Ambient Air Quality Standards

Based on EPA's guidance, *New Source Review Workshop Manual*, October 1990, if the maximum modeled impact for the proposed project does not exceed the Class II significant impact levels then EPA does not require any further National Ambient Air Quality Standards or PSD Class II increment analyses for that pollutant. DENR recommends using these significant impact levels to determine if a more refined analysis is warranted. Table 7-126 displays a comparison of the maximum modeled concentrations to the significant impact levels. Hyperion triggered a Prevention of Significant Program review for particulate matter 10 microns in diameter or less (PM10), sulfur dioxide, carbon monoxide, and nitrogen oxide.

Table 7-126 – PSD Class II Significant Modeling Impact Levels

Pollutant	Averaging Period	Hyperion Project Modeled Impact (ug/m^3)	Significant Impact Level (ug/m^3)	Further Analysis Required
PM-10	24-hour	19.9	5	Yes
	Annual	3.03	1	Yes
SO2	3-hour	199	25	Yes
	24-hour	55.9	5	Yes
	Annual	4.71	1	Yes
NOx	Annual	2.40	1	Yes
CO	1-hour	1,609	2,000	No
	8-hour	464	500	No

The modeled concentration for the project does not exceed the carbon monoxide significant modeling impact levels. No further modeling review is required for carbon monoxide.

Based on the Class II significant impact level review, the National Ambient Air Quality standards review is necessary for particulate matter 10 microns in diameter or less (PM10), sulfur dioxide, and nitrogen oxide. As required in 40 CFR §52.21(d), the analysis was conducted to determine if the project would exceed the National Ambient Air Quality Standards for those pollutants. The modeled concentration from the proposed project was added to the background concentration to compare to the National Ambient Air Quality Standards. Table 7-127 displays the comparison of the modeled impacts to the National Ambient Air Quality Standards and demonstrates that the National Ambient Air Quality Standards will not be exceeded.

Table 7-127 – National Ambient Air Quality Standards Comparison

Pollutant	Modeled Impact[1] (ug/m^3)	Monitored Background[2] (ug/m^3)	Total Impact (ug/m^3)	NAAQS (ug/m^3)	NAAQS Violation
PM2.5 (24-hour)	11.30	23	34.3	35	No
PM2.5 (annual)	2.94	9	11.9	15	No
PM10 (24-hour)	30.30	49	79	150	No
PM10 (annual)	3.60	19	23	50	No

Pollutant	Modeled Impact[1] (ug/m^3)	Monitored Background[2] (ug/m^3)	Total Impact (ug/m^3)	NAAQS (ug/m^3)	NAAQS Violation
SO_2 (3-hour)	141.8	21	163	1,300	No
SO_2 (24-hour)	49.81	5	55	365	No
SO_2 (Annual)	5.86	3	8.9	80	No
NOx (Annual)	3.35	10	13.3	100	No

[1] – Maximum impacts shown for annual averaging periods. Highest 2nd high values shown for short-term averaging periods; and
[2] – The monitored background is based on the monitoring data collected in Sioux Falls during the calendar year 2006 for the Hilltop monitoring station.

Hyperion modeled the roads at the site as if they were paved, that specific units would operate a limited number of hours per year and did not model those units that would be used as redundant operations. The PSD permit will specify that the roads must be paved, the equipment is limited to a number of hours per year and that only so many systems may be operated at one given time.

DENR conducted air dispersion modeling in order to compare results of the NAAQS impacts with those listed in the application. The report of DENR's modeling analysis is located in Appendix A. To conduct the comparison, DENR modeled the same BACT limits proposed by Hyperion. However, DENR has proposed more stringent BACT limits in some cases and required additional control such as the tank farm thermal oxidizer. The increases of emissions from the thermal oxidizers associated with the tank farm are considered negligible compared to the reductions achieved by the more stringent limitations proposed by DENR for other units. Modeling emission rates higher than will be allowed by the permit is a conservative approach.

Table 7-128 shows the results of this comparison.

Table 7-128 – National Ambient Air Quality Standard Impact Comparison

Pollutant	Hyperion Modeled Total Impact (ug/m^3)	DENR Modeled Total Impact (ug/m^3)	% Difference
PM10 (24-hour)	79.3	74.1	7%
PM10 (annual)	22.6	22.6	0%
SO_2 (3-hour)	162.8	178.1	9%
SO_2 (24-hour)	54.9	54.9	0%
SO_2 (Annual)	8.9	8.9	0%
NOx (Annual)	13.4	13.4	0%

Note: Maximum impacts shown for annual averaging periods. Highest 2nd high values shown for short-term averaging periods.

DENR's modeled results differed from those submitted by Hyperion in two cases. The difference in concentration is due to DENR using a coarser receptor grid. The highest modeled concentrations from the NAAQS analysis by both DENR and Hyperion occur in the far south end of the receptor grid. Hyperion's receptor grid extended two kilometers further south than the receptor grid used by DENR. Based on the results of the impact analysis for just the Hyperion's sources, Hyperion's contribution to the concentrations at these locations is minor, contributing less than one microgram per cubic meter. The major contribution to the concentration at these locations is from existing sources.

DENR agrees that the air emissions from the proposed facility will not cause a violation of the National Ambient Air Quality Standards for particulate matter 10 microns in diameter or less (PM10), sulfur dioxide, and nitrogen oxide.

7.2.3 Increment Consumption

Hyperion is proposing to construct in Union County. There is a disparity on how South Dakota handles its baseline areas for tracking increments and how EPA established those areas for South Dakota. South Dakota considers the baseline areas to be by county. DENR has not received a PSD application for Union County. Hyperion would trigger the Minor Source Baseline Date for Union County.

EPA established the baseline areas as the entire state for nitrogen oxide and sulfur dioxide and the Rapid City area and the rest of the state for particulate matter. The PSD rules define a baseline area as an intrastate area. An intrastate area is an area within a state. The areas designated by EPA do not meet the requirement of an intrastate area. However, based on how EPA established the baseline areas, the minor source date for Union County would be triggered by Northern States Power Company's PSD permit application submitted to EPA in 1991.

Due to this disparity, Hyperion based the increment analysis of the worse case scenario, which would consider the Minor Source baseline date as being triggered in 1991 and not with Hyperion's application. Hyperion included the offsite sources shown in Table 7-129 in the increment consumption analysis.

Table 7-129 – Offsite Sources for Increment Analysis

Modeled ID	Description	Modeled ID	Description
SD1	University of SD - Boilers	IA20	Midamerican George Neal South – EP22
SD2	Northwestern Public Service – Generators	IA21	Midamerican George Neal South – E23
SD4	Midwest Ready Mix	IA22	Terra Nitrogen Port Neal – EP1
SD5	Vermillion Fertilizer and Grain	IA23	Terra Nitrogen Port Neal – EP1N
IA1	Midamerican George Neal North – EP3	IA24	Terra Nitrogen Port Neal – EP2
IA2	Midamerican George Neal North – EP1	IA25	Terra Nitrogen Port Neal – EP4

Modeled ID	Description	Modeled ID	Description
IA3	Midamerican George Neal North – EP2	IA26	Terra Nitrogen Port Neal – EP7
IA4	Midamerican George Neal North – EP9	IA27	Terra Nitrogen Port Neal – EP21
IA5	Midamerican George Neal North – EP37	IA28	Terra Nitrogen Port Neal – EP22
IA6	Midamerican George Neal North – EP38	IA29	Terra Nitrogen Port Neal – EP25
IA7	Midamerican George Neal North – EP11	NE1	Siouxland Ethanol – Thermal Oxidizer
IA8	Midamerican George Neal North – EP10	NE2	Siouxland Ethanol – Receiving
IA9	Midamerican George Neal North – EP8	NE3	Siouxland Ethanol – Hammer Milling Baghouse
IA10	Midamerican George Neal North – EP7	NE4	Siouxland Ethanol – CO2 Scrubber
IA11	Midamerican George Neal North – EP6	NE5	Siouxland Ethanol – Truck Loadout Flare
IA12	Midamerican George Neal North – EP36	NE6	Siouxland Ethanol – Methanator Flare
IA13	Midamerican George Neal North – EP35	NE7	Siouxland Ethanol – DDGS Cooling Baghouse
IA14	Midamerican George Neal South – EP3	NE8	Siouxland Ethanol – Cooling Tower
IA15	Midamerican George Neal South – EP6	NE9	Siouxland Ethanol – Cooling Tower
IA16	Midamerican George Neal South – EP8	NE10	Siouxland Ethanol – Cooling Tower
IA17	Midamerican George Neal South – EP7	NE11	Siouxland Ethanol – Cooling Tower
IA18	Midamerican George Neal South – EP9	NE12	Siouxland Ethanol – DDGS Loadout Baghouse
IA19	Midamerican George Neal South – EP10	NE13	Siouxland Ethanol – Emergency Water Pump
		NE14	Tyson-Dakota City (IBP)

In accordance with 40 CFR §52.21(c), Hyperion must demonstrate that the PSD Class II increments will not be exceeded. Table 7-130 displays the amount of increments consumed based on the emission limits that will be placed in the permit for the units.

Table 7-130 – PM10 Increment Consumption

Pollutant	Modeled Concentration (ug/m^3) [1]	PSD Class II Increments		Increments Consumed
		Amount (ug/m^3)	Remaining (ug/m^3)	
PM10 (24-hour)	28.07	30 [2]	1.9	No
PM10 (annual)	3.56	17	13.4	No
SO_2 (3-hour)	141.8	512	370.2	No
SO_2 (24-hour)	49.81	91	41.2	No
SO_2 (Annual)	5.78	20	14.2	No

Pollutant	Modeled Concentration (ug/m^3) [1]	PSD Class II Increments Amount (ug/m^3)	PSD Class II Increments Remaining (ug/m^3)	Increments Consumed
NOx (Annual)	3.20	25	21.8	No

[1] – Maximum impacts shown for annual averaging periods. Highest 2nd high values shown for short-term averaging periods; and
[2] – Can be exceeded once per year.

Based on this analysis, the proposed facility will not exceed the PSD increments and allows for economic growth in the area.

DENR conducted air dispersion modeling in order to compare results of the PSD increments with those listed in the application. The report of DENR's modeling analysis is located in Appendix A. To conduct the comparison, DENR modeled the same BACT limits proposed by Hyperion. However, DENR has proposed more stringent BACT limits in some cases and required additional control such as the tank farm thermal oxidizer. The increases of emissions from the thermal oxidizers associated with the tank farm are considered negligible compared to the reductions achieved by the more stringent limitations proposed by DENR for other units. Modeling emission rates higher than will be allowed by the permit is a conservative approach.

Table 7-131 shows the results of this comparison.

Table 7-131 – PSD Increment Comparison

Pollutant	Hyperion Modeled Impact (ug/m^3)	DENR Modeled Impact (ug/m^3)	% Difference
PM10 (24-hour)	28.07	25.07	11%
PM10 (annual)	3.56	3.56	0%
SO_2 (3-hour)	141.8	157.6	11%
SO_2 (24-hour)	49.8	49.9	0%
SO_2 (Annual)	5.78	5.88	1%
NOx (Annual)	3.20	3.27	2%

Note: Maximum impacts shown for annual averaging periods. Highest 2nd high values shown for short-term averaging periods.

DENR's modeled results differed from those submitted by the applicant. The difference in concentration is due to DENR using a coarser receptor grid. For example, the highest modeled concentrations from the particulate PSD increment by both DENR and Hyperion occur in far south end of the receptor grid. Hyperion's receptor grid extended two kilometers further south than the receptor grid used by DENR. Based on the results of the impact analysis for just the Hyperion's sources, Hyperion's contribution to the concentrations at these locations is minor. The major contribution to the concentration at these locations is from existing sources.

DENR agrees that the air emissions from the proposed facility will not cause a violation of the PSD increments for PM10, sulfur dioxide, and nitrogen oxide.

7.2.4 Class I Area Impacts

The models that are used to determine impacts for a Class I area are valid up to approximately 300 kilometers. Hyperion will be located near Elk Point, South Dakota, which is greater than 300 kilometers away from any Class I area. On July 23, 2008, the National Park Service emailed DENR noting that a Class I analysis was not required.

7.3.4 Other Impacts

7.3.4.1 Visibility

Hyperion performed a Level-1 visibility analysis using EPA's VISCREEN model for all National Park Service facilities within 300 kilometers of the project site, which includes the following:

- Homestead National Monument (167 km);
- Lewis and Clark National Historic Trail (106 km);
- Niobrara National Scenic River (101 km);
- Pipestone National Monument (92 km); and
- The Missouri National Recreational River (13 km).

Maximum PM10 emissions of 249 pounds per hour and nitrogen oxide emissions of 281 pounds per hour were entered into the VISCREEN model and compared them to the screening values for Delta E (2) and Green Contrast (0.05). Delta E (also known as a color contrast) describes the extent at which the color brightness and contrasts between the emissions and the background will change. If the model indicates a Delta E greater than 2, then there is just a slight perceptible change. The Green Contrast (also known as a plume contrast) describes the relative brightness between the emissions and the background at a specific color wavelength. The green color wavelength is in the middle of the visible spectrum. If the model indicates a Green Contrast greater than 0.05, then there is a slight perceptible change.

Based on the conservative assumptions associated with the Level-1 analysis, visibility is not anticipated to be affected, except at the Missouri National Recreational River. Exceedances of the default Delta E and Green Contrast parameters were calculated in this park. Therefore a more refined Level-3 PLUVUE II analysis was performed.

For the refined analysis, the maximum emissions of 2.99 tons per day (average 249 pounds per hour) of particulate matter emissions, 3.37 tons per day (average 281 pounds per hour) of nitrogen oxide emissions and 2.34 tons (average of 195 pounds per hour) of sulfur dioxide emissions. In this analysis the screening values of Delta E (1.0) and contrast (0.02) were recommended in the PLUVUE users guide. The results of the PLUVUE analysis are shown in Table 7-132. As shown, the maximum calculated plume contrast and Delta E values are below threshold values, indicating that the facility will not impact visibility at the park.

Table 7-132 – PLUVUE Analysis

Day	Delta E		Green Contrast	
	Criterion	Calculated Plume	Criterion	Calculated Plume
March 21	1.0	0.194	0.02	0.002
June 21	1.0	0.228	0.02	0.002
September 21	1.0	0.193	0.02	0.001
December 21	1.0	0.184	0.02	0.000

7.3.4.2 Commercial, Residential, and Industrial Growth

The Hyperion project is expected to have an operations phase workforce of 1,826 direct workers and may result in up to 14,147 induced and indirect new jobs. Residential and commercial growth resulting from the facility will result in secondary air emissions. Depending on the pollutant, Hyperion projects less than a 6% increase in emissions due to residential or commercial growth. DENR does not anticipate that this increase of emissions would significantly affect the air quality in Union County.

7.3.4.3 Soils and Vegetation

The soil and vegetation analysis considered the impacts that air pollutants would have on the soil and vegetation in the vicinity of the proposed facility. Hyperion focused the analysis on agricultural crops because the land use around the proposed facility is predominantly agricultural.

The application notes that the modeled ambient sulfur dioxide impacts are well below the secondary NAAQS of 1,300 micrograms per cubic meter (3-hour average) and 78 micrograms per cubic meter (annual average). Secondary NAAQS were established to protect plant and animal health. The modeled ambient impacts are also well below the minimum EPA screening values of 786 micrograms per cubic meter (3-hour average) and 18 micrograms per cubic meter (annual average). The minimum EPA screening values are listed as being protective for agricultural crops like alfalfa, apple, corn, soybeans, and wheat.

The application notes that the modeled ambient nitrogen oxide impacts are well below the second NAAQS of 100 micrograms per cubic meter (annual average). Secondary NAAQS were established to protect plant and animal health. The modeled ambient impacts are also well below the minimum EPA screening values of 94 micrograms per cubic meter (annual average). The minimum EPA screening values are listed as being protective for agricultural crops like alfalfa, barley, corn, oats, sorghum, and wheat.

The application notes that modeled ambient heavy metals impacts are well below literature values indicating these deposition rates would not have a detrimental impact on the agricultural crops.

Carbon monoxide is not known to injure plants.

DENR does not anticipate any adverse impacts on soils and terrestrial vegetation in this area from this project.

7.4 Operational Restrictions

Hyperion's BACT analysis and/or modeling analysis noted specific operational cases. These operational representations need to be included in the permit as operational limitations to validate the BACT analysis and/or modeling analysis. The first permit condition requires Hyperion to operate the facility as it is represented in the application, unless otherwise specified in the permit. However, to clarify those operational limitations, the following operational limits will be spelled out in the permit, which is not all inclusive:

1. The refinery design capacity of refining 400,000 barrels of crude oil per day;
2. The production of hydrogen, electricity, and steam from the IGCC system is limited to on-site use;
3. The design parameter of the drift eliminator for the cooling tower;
4. The leak detection and repair program for the cooling tower heat exchangers;
5. The roads and parking lots shall be paved;
6. The requirements that all flares shall meet the design specification in 40 CFR §60.18;
7. The minimum requirements of the flare minimization plan. The plan needs to be robust to allow the facility the flexibility to change the plan under any foreseeable and unforeseeable issues;
8. That only four of the six sulfur recovery plant trains and thermal oxidizer may be operated at any given time. The trains and thermal oxidizer will be allowed to overlap while one is shutting down and another one is starting up;
9. That only four of the five combined cycle combustion turbines may be operated at any give time. The operations of the combined cycle combustion turbines will be able to overlap while one is shutting down and another one is starting up;
10. That the five combined cycle combustion turbine system will not operate greater than 500 hours per 12-month rolling period on ultra low sulfur distillate oil;
11. That only six of the eight gasifier startup burners may be operated at any given time. The operations of the gasifier startup burners will be able to overlap while one is shutting down and another one is starting up;
12. The work practice standards for the wastewater treatment facility;

13. The work practice standards for the leak detection and repair program for valves, pumps, compressors, etc.;
14. The work practice standards for fugitive dust sources; and
15. The diesel generators and fuel pumps must be 2008 models or newer and will be limited to 300 hours per year. The operations during an actual emergency are not counted against this limitation.

7.5 Compliance Demonstration

There are several methods that may be used to demonstrate compliance with the proposed numerical emission limits such as performance tests and/or continuous emission monitoring. The averaging period, the quantity of emissions, how frequent does the system operate are used to determine the most appropriate compliance. Table 7-133, identifies the applicable unit and if DENR recommends a performance test, or continuous emission monitoring system or design criteria as the compliance demonstration.

Table 7-133 Compliance Method

Unit	Particulate	Sulfur Dioxide	Nitrogen Oxide	Volatile Organic Compounds	Carbon Monoxide	Hydrogen Sulfide
#1	Stack Test	CEM[1]	CEM[1]	Stack Test	CEM[1]	WPS[2]
#2	Stack Test	CEM[1]	CEM[1]	Stack Test	CEM[1]	WPS[2]
#3	Stack Test	CEM[1]	CEM[1]	Stack Test	CEM[1]	WPS[2]
#4	Stack Test	CEM[1]	CEM[1]	Stack Test	CEM[1]	WPS[2]
#5	Stack Test	CEM[1]	CEM[1]	Stack Test	CEM[1]	WPS[2]
#6	Stack Test	CEM[1]	CEM[1]	Stack Test	CEM[1]	WPS[2]
#7	Stack Test	CEM[1]	CEM[1]	Stack Test	CEM[1]	WPS[2]
#8	Stack Test	CEM[1]	CEM[1]	Stack Test	CEM[1]	WPS[2]
#9	Stack Test	CEM[1]	CEM[1]	Stack Test	CEM[1]	WPS[2]
#10	Stack Test	CEM[1]	CEM[1]	Stack Test	CEM[1]	WPS[2]
#11	Stack Test	CEM[1]	CEM[1]	Stack Test	CEM[1]	WPS[2]
#12	Stack Test	CEM[1]	CEM[1]	Stack Test	CEM[1]	WPS[2]
#13	Stack Test	CEM[1]	CEM[1]	Stack Test	CEM[1]	WPS[2]
#14	Stack Test	CEM[1]	CEM[1]	Stack Test	CEM[1]	WPS[2]
#15	Stack Test	CEM[1]	CEM[1]	Stack Test	CEM[1]	WPS[2]
#16	Stack Test	CEM[1]	CEM[1]	Stack Test	CEM[1]	WPS[2]
#17	Stack Test	CEM[1]	CEM[1]	Stack Test	CEM[1]	WPS[2]
#18	Stack Test	CEM[1]	CEM[1]	Stack Test	CEM[1]	WPS[2]
#19	Stack Test	CEM[1]	CEM[1]	Stack Test	CEM[1]	WPS[2]
#20	Stack Test	CEM[1]	CEM[1]	Stack Test	CEM[1]	WPS[2]
#21	Stack Test	CEM[1]	CEM[1]	Stack Test	CEM[1]	WPS[2]
#22	Stack Test	CEM[1]	CEM[1]	Stack Test	CEM[1]	WPS[2]
#23	Stack Test	CEM[1]	CEM[1]	Stack Test	CEM[1]	WPS[2]
#24	Stack Test	CEM[1]	CEM[1]	Stack Test	CEM[1]	WPS[2]
#25	Stack Test	CEM[1]	CEM[1]	Stack Test	CEM[1]	WPS[2]

Unit	Particulate	Sulfur Dioxide	Nitrogen Oxide	Volatile Organic Compounds	Carbon Monoxide	Hydrogen Sulfide
#26	Stack Test	CEM[1]	CEM[1]	Stack Test	CEM[1]	WPS[2]
#27	Stack Test	CEM[1]	CEM[1]	Stack Test	CEM[1]	WPS[2]
#28	Stack Test	CEM[1]	CEM[1]	Stack Test	CEM[1]	WPS[2]
#29	Stack Test	CEM[1]	CEM[1]	Stack Test	CEM[1]	WPS[2]
#30	Stack Test	CEM[1]	CEM[1]	Stack Test	CEM[1]	WPS[2]
#31	Stack Test	Stack Test	Stack Test	NA [3]	Stack Test	NA [3]
#32	Stack Test	Stack Test	Stack Test	NA [3]	Stack Test	NA [3]
#33	Stack Test	Stack Test	Stack Test	NA [3]	Stack Test	NA [3]
#34a	WPS[2]	NA [3]	NA [3]	WPS[2]	WPS[2]	NA [3]
#34b	WPS[2]	NA [3]	NA [3]	WPS[2]	WPS[2]	NA [3]
#34c	WPS[2]	NA [3]	NA [3]	WPS[2]	WPS[2]	NA [3]
#34d	WPS[2]	NA [3]	NA [3]	WPS[2]	WPS[2]	NA [3]
#35a	WPS[2]	NA [3]	NA [3]	WPS[2]	WPS[2]	NA [3]
#35b	WPS[2]	NA [3]	NA [3]	WPS[2]	WPS[2]	NA [3]
#35c	WPS[2]	NA [3]	NA [3]	WPS[2]	WPS[2]	NA [3]
#35d	WPS[2]	NA [3]	NA [3]	WPS[2]	WPS[2]	NA [3]
#36	WPS[2]	WPS[2]	WPS[2]	WPS[2]	WPS[2]	WPS[2]
#37	WPS[2]	WPS[2]	WPS[2]	WPS[2]	WPS[2]	WPS[2]
#38	WPS[2]	WPS[2]	WPS[2]	WPS[2]	WPS[2]	WPS[2]
#39	WPS[2]	WPS[2]	WPS[2]	WPS[2]	WPS[2]	WPS[2]
#40	WPS[2]	WPS[2]	WPS[2]	WPS[2]	WPS[2]	WPS[2]
#41	WPS[2]	NA [3]	NA [3]	WPS[2]	NA [3]	NA [3]
#42a	Stack Test	CEM[1]	CEM[1]	Stack Test[5]	CEM[1]	Stack Test[5]
#42b	Stack Test	CEM[1]	CEM[1]	Stack Test[5]	CEM[1]	Stack Test[5]
#42c	Stack Test	CEM[1]	CEM[1]	Stack Test[5]	CEM[1]	Stack Test[5]
#42d	Stack Test	CEM[1]	CEM[1]	Stack Test[5]	CEM[1]	Stack Test[5]
#42e	Stack Test	CEM[1]	CEM[1]	Stack Test[5]	CEM[1]	Stack Test[5]
#42f	Stack Test	CEM[1]	CEM[1]	Stack Test[5]	CEM[1]	Stack Test[5]
#43	NA [3]	NA [3]	NA [3]	Stack Test	NA [3]	NA [3]
#44	NA [3]	NA [3]	NA [3]	Stack Test	NA [3]	NA [3]
#45a	Stack Test	CEM[1]	CEM[1]	Stack Test	Stack Test	NA [3]
#45b	NA [3]	NA [3]	NA [3]	WPS[2]	NA [3]	NA [3]
#45c	NA [3]	NA [3]	NA [3]	WPS[2]	NA [3]	NA [3]
#46a	Stack Test	NA [3]	NA [3]	NA [3]	NA [3]	NA [3]
#46b	Stack Test	NA [3]	NA [3]	NA [3]	NA [3]	NA [3]
#46c	Stack Test	NA [3]	NA [3]	NA [3]	NA [3]	NA [3]
#46d	Stack Test	NA [3]	NA [3]	NA [3]	NA [3]	NA [3]
#47	Stack Test	NA [3]	NA [3]	NA [3]	NA [3]	NA [3]
#48	Stack Test	NA [3]	NA [3]	NA [3]	NA [3]	NA [3]
#49	Stack Test	NA [3]	NA [3]	NA [3]	NA [3]	NA [3]
#50	WPS[2]	WPS[2]	WPS[2]	WPS[2]	WPS[2]	WPS[2]
#51	Stack Test[4]	WPS[2]	Stack Test[4]	Stack Test[4]	Stack Test[4]	WPS[2]

Unit	Particulate	Sulfur Dioxide	Nitrogen Oxide	Volatile Organic Compounds	Carbon Monoxide	Hydrogen Sulfide
#52	Stack Test[4]	WPS[2]	Stack Test[4]	Stack Test[4]	Stack Test[4]	WPS[2]
#53	Stack Test[4]	WPS[2]	Stack Test[4]	Stack Test[4]	Stack Test[4]	WPS[2]
#54	Stack Test[4]	WPS[2]	Stack Test[4]	Stack Test[4]	Stack Test[4]	WPS[2]
#55	Stack Test[4]	WPS[2]	Stack Test[4]	Stack Test[4]	Stack Test[4]	WPS[2]
#56	Stack Test[4]	WPS[2]	Stack Test[4]	Stack Test[4]	Stack Test[4]	WPS[2]
#57	Stack Test[4]	WPS[2]	Stack Test[4]	Stack Test[4]	Stack Test[4]	WPS[2]
#58	Stack Test[4]	WPS[2]	Stack Test[4]	Stack Test[4]	Stack Test[4]	WPS[2]
#59	NA [3]	NA [3]	NA [3]	NA [3]	CEM[1]	CEM[1]
#60	Stack Test	CEM[1]	CEM[1]	Stack Test	CEM[1]	WPS[2]
#61	Stack Test	CEM[1]	CEM[1]	Stack Test	CEM[1]	WPS[2]
#62	Stack Test	CEM[1]	CEM[1]	Stack Test	CEM[1]	WPS[2]
#63	Stack Test	CEM[1]	CEM[1]	Stack Test	CEM[1]	WPS[2]
#64	Stack Test	CEM[1]	CEM[1]	Stack Test	CEM[1]	WPS[2]
#65	WPS[2]	WPS[2]	WPS[2]	WPS[2]	WPS[2]	NA [3]
#66	WPS[2]	WPS[2]	WPS[2]	WPS[2]	WPS[2]	NA [3]
#67	WPS[2]	WPS[2]	WPS[2]	WPS[2]	WPS[2]	NA [3]
#68	WPS[2]	WPS[2]	WPS[2]	WPS[2]	WPS[2]	NA [3]
#69	WPS[2]	WPS[2]	WPS[2]	WPS[2]	WPS[2]	NA [3]
#70	WPS[2]	WPS[2]	WPS[2]	WPS[2]	WPS[2]	NA [3]
#175	Stack Test	CEM[1]	Stack Test	Stack Test	Stack Test	NA [3]

[1] – CEM stands for continuous emission monitoring system;
[2] – WPS stands for work practice standard, design standard or a surrogate approach is used for a compliance demonstration;
[3] – NA means there are no or a negligible quantity of the specified emissions from this system;
[4] – The gasifier startup burners operate infrequently and are considered small emission sources. DENR recommends only one of the eight gasifiers be stack tested. The one test will be considered representative of the other seven; and
[5] – The volatile organic compounds BACT limit is based on good combustion practices. DENR is requiring a carbon monoxide continuous emission system. Carbon monoxide is a good indicator of good combustion practices. DENR recommends only one of the six thermal oxidizers be stack tested. The one test will be considered representative of the other five.

The August 7, 1980, federal register notice, page 52698, notes that an increase of emissions occurs when the unit becomes operational and begins to emit a pollutant. The federal register notice continues to state that “any unit that requires shakedown becomes operational after a reasonable shakedown period (not to exceed 180 days). Compliance with the emission limits is allowed to occur after a reasonable shakedown period. DENR is requiring Hyperion to conduct hundreds of performance tests to certify the continuous emission monitoring systems and demonstrate compliance. There are logistic issues such as the availability of stack testing teams, scheduling issues to complete this number of tests at one given time. DENR is recommending that the certification of the continuous emission monitoring systems be completed within 60 days of achieving maximum production or within 180 days after initial startup of the refinery, whichever comes first. DENR is recommending that the stack tests be staggered out over three years to help alleviate some of these logistic issues.

8.0 State Requirements

Any source operating in South Dakota that meets the requirements of Administrative Rules of South Dakota (ARSD) 74:36:05:03 is required to obtain a Title V air quality permit. Hyperion is required to obtain a Title V air quality permit because their potential criteria pollutant air emissions are greater than 100 tons per year. In accordance with the ARSD 74:36:05:03.01, Hyperion is required to submit an application for a Title V air quality permit within 12 months after commencing operation.

South Dakota has established particulate matter, sulfur dioxide, and opacity emission limits in ARSD 74:36:06 and 74:36:12. In accordance with ARSD 74:36:06:01, the particulate matter and sulfur dioxide emission limits in ARSD 74:36:06 are not applicable if a particulate matter and sulfur dioxide emission limit specified in ARSD 74:36:07 (NSPS program) or in ARSD 74:36:09 (PSD program) are applicable. Hyperion is obtaining a PSD air quality permit. In Hyperion’s PSD application, Hyperion is proposing particulate matter and sulfur dioxide emission limits for the proposed equipment. In addition, Hyperion is required to meet particulate matter and sulfur dioxide limits under the NSPS regulations. Therefore, South Dakota’s particulate matter and sulfur dioxide emission limits are not applicable.

In accordance with ARSD 74:36:12:01, the Hyperion project is required to maintain visible emissions from the permitted equipment at less than 20 percent opacity.

9.0 Recommendation

Based on the information submitted in the air permit application, DENR recommends conditional approval of a PSD air quality permit. Any questions pertaining to this permit recommendation should be directed to Kyrik Rombough, Natural Resources Engineering Director.

Appendix A

DENR's Air Quality Analysis

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1.0 Background Information

The existing air quality or background concentration is defined by the existing natural and human-generated sources of air pollution. The area surrounding the Hyperion is considered rural and in attainment for all regulated pollutants. Dispersion modeling is intended to provide conservative estimates of ambient air quality concentrations that may potentially result from the proposed project emissions in combination with emissions from existing nearby sources. The estimated total concentrations were used to demonstrate compliance with the National Ambient Air Quality Standards (NAAQS) and Prevention of Significant Deterioration (PSD) Increments.

The estimate of the ambient air quality concentration is accomplished by modeling Hyperion's emissions and nearby sources. This modeled concentration is then added to a background concentration, which is obtained from ambient air quality monitors. The summation of the two concentrations (modeled and monitored) is then compared to the NAAQS.

The estimate of the increase of the concentration in the ambient air is accomplished by modeling Hyperion's emissions and other nearby sources constructed after the calendar year 1991. The modeled concentration is then compared to the PSD Increments.

2.0 Model Selection

Estimates of ambient concentrations are based upon applicable air quality models, databases and other requirements specified in Appendix W of 40 CFR Part 51 (Guideline on Air Quality Models). The current version of the American Meteorological Society/Environmental Protection Agency Regulatory Model (AERMOD) was used to estimate impacts for particulate matter, nitrogen oxide (NOx) and sulfur dioxide (SO_2). The modeling analysis was conducted using the regulatory default options. Building wake and downwash effects were accounted for using the Building Profile Input Program (BPIP). Current version numbers of the AERMOD model and pre-processors that were used include:

- AERSURFACE, version 08009;
- AERMET, version 06341;
- AERMAP, version 06341;
- BPIP, version 04274; and
- AERMOD, version 07026.

AERMOD is recommended for use in modeling multi-source emissions, and can account for plume downwash, stack tip downwash, and point, area, and volume sources (USEPA 2005, 2004). AERMOD also has the ability to model impacts over both simple (below stack height) and complex (above the height of the stack) terrain.

3.0 Model and Pre-processor Inputs

3.1 AERSURFACE

EPA has developed the AERSURFACE processor to calculate the surface characteristics (Albedo, Bowen Ration, and surface roughness length) based on land cover data for the study area and output in a format for use in AERMET. AERSURFACE requires the input of digitized land cover data from the U.S. Geological Survey (USGS) National Land Cover Data 1992 archives (NLCD92).

AERSURFACE matches the NLCD92 land cover categories to seasonal values of Albedo, Bowen ratio, and surface roughness. DENR downloaded and used the South Dakota .tif file available at http://edcftp.cr.usgs.gov/pub/data/landcover/states/.

AERSURFACE asks the user to enter the type of coordinates to be used for the center of the study area site. The AERSURFACE users guide states the center of the study area be the location of the surface station meteorological tower (measurement site). AERSURFACE uses these coordinates to extract land cover data for the area of interest from the NLCD92 data file. Per the guidance cited above, DENR used the surface station coordinates shown in Table A-2.

Land cover categories in the NLCD92 file are linked within AERSURFACE to a set of seasonal surface characteristics. The values of seasonal surface characteristics by land cover category were developed for the continental U.S. for the five seasonal categories. AERSURFACE provides the option of choosing which months belong to which seasonal category for the site specific climate. DENR used the program's default setting which assigns the months of March, April, and May to seasonal category 5 ("Transitional spring with partial green coverage or short annuals"); June, July, and August to seasonal category 1 ("Midsummer with lush vegetation"); September, October, and November to seasonal category 2 ("Autumn with unharvested cropland"); and December, January, and February to seasonal category 4 ("Winter with continuous snow on ground").

Because the land cover classifications of NLCD92 are applied across the continental U.S., there are instances where the surface characteristic values for two areas of the U.S. may differ, although the land cover type is the same. To address the issue AERSURFACE asks the user to specify three characteristics of the meteorological station where the surface data was recorded. The questions and DENR response for the surface meteorological station explained below:

- ***"Is this site at an airport?"*** If the site is at an airport, AERSURFACE will use surface characteristics that reflect an area more dominated by transportation land cover. If the user answers "No" to the above question, AERSURFACE will choose higher surface roughness values that are more representative of an area dominated by buildings associated with commercial and industrial land cover. DENR identified the Sioux Falls/Foss Field met station as being located at an airport;
- ***"Is this site in an arid region?"*** If the user answers "Yes" AERSURFACE uses the seasonal surface characteristics for the Shrubland and Bare Rock/Sand/Clay categories that are more representative of a desert area. Otherwise, AERSURFACE uses the seasonal surface characteristics for the non-arid area. The Sioux Falls met station is located in eastern South Dakota, which is not an arid region. Therefore, DENR identified the region as non-arid for this analysis;
- ***"Characterize the surface moisture condition at the site relative to climatological normals, to be applied for all periods. Enter 'A' for Average, 'W' for Wet, or 'D' for Dry."*** The answer to this question affects the value of the Bowen ratio. The current version of AERSURFACE applies the user defined surface moisture condition for the entire met data period. The surface moisture condition is determined by comparing precipitation for the period of met data to be processed to the 30-year climatological record, selecting "wet" conditions if precipitation is in the upper 30th-percentile, "dry" conditions if precipitation is in the lower 30th-percentile, and "average" conditions if precipitation is in the middle 40th-percentile.

According to the National Climatic Data Center publication of precipitation probabilities for the Sioux Falls met station the middle 40th-percentile precipitation (based on records from 1971-2000) corresponds to annual precipitation of between 20.65 and 30.23 inches. Table A-1 displays the annual precipitation recorded at the site for the corresponding years of met data and surface moisture condition used in processing that years met data.

Table A-1 – Surface Moisture Condition 2000-2004

Surface Moisture	2000	2001	2002	2003	2004
Actual Precipitation Recorded (inches)	26.11	30.18	24.07	21.81	30.92
Surface Moisture Condition	Average	Average	Average	Average	Wet

The user is given the option of defining the surface roughness length for multiple sectors, up to a maximum of 12. DENR selected the maximum of 12 sectors for this analysis.

The user must enter a distance of 0.1 to 5.0 km from the center of the site location to be used in calculating the effective surface roughness length. AERSURFACE uses this information, along with the coordinates of the center of the study area, to extract a subsection of land cover data from the NLCD92 data file. AERMOD Implementation Guide Addendum published January 9, 2008, the recommended upwind distance for processing land cover data to determine the effective surface roughness for input to AERMET is 1 kilometer relative to the meteorological tower location. Therefore, DENR used a radius of 1 km in this analysis; and

- ***"Does the site experience continuous snow cover in the winter months?"*** Because the surface characteristics are affected by snow cover, this question is asked of the user to determine whether surface characteristics for continuous snow cover should be used. The wording of this prompt will vary as shown depending on the temporal resolution for outputs specified by the user. According to the National Climatic Data Center publication of average snow monthly snow depth recorded at Worthington, MN (1971-2000), which was the closest site to Hyperion's proposed project, 100 miles east of the Sioux Falls meteorological station, the area normally has continuous snow cover of 3-4 inches during the winter period (December, January, and February). Therefore, DENR selected "Yes" to this question.

3.2 AERMET

EPA developed the AERMET processor as a general purpose meteorological preprocessor for organizing different available meteorological data sets into a format suitable for use in AERMOD. The AERSURFACE output described above, surface meteorological data, and upper air sounding data are input in the AERMET processor.

Surface meteorological data from the National Weather Service station at the Foss Field Airport in Sioux Falls, South Dakota for the years 2000-2004 were used by DENR. All years had better than 98 percent data recovery on an annual basis.

The temperature structure of the atmosphere prior to sunrise is required by AERMET to estimate the growth of the convective boundary layer for each day. AERMET uses upper air soundings from the nearest upper air observing station for this purpose. Concurrent 2000-2004 upper air data from the National Weather Service upper air station in Omaha, Nebraska for the years 2000-2004 were used by DENR in this analysis. Table A-2 lists the details of the met stations used in the modeling.

Table A-2 – Met Station Details

Station	WBAN ID	Degrees [1] Latitude	Degrees[1] Longitude	Elevation (m)	Anemometer Height (m)	Time Zone
Sioux Falls Surface Station (KFSD)	14944	43.577	96.754	435.5	10	6
Omaha Upper Air Station (KOAX)	94980	41.316	96.367	350.1	Not Applicable	6

[1] – Datum = NAD 83.

The processing carried out by AERMET is location-dependent. The application site is likely to be different from either of the meteorological sites specified for the SURFACE and UPPERAIR data. The latitude and longitude entered here are used to calculate the elevation of the sun and the times of sunrise and sunset. DENR input 42.823 N latitude, 96.744 W longitude, and 372 meters of elevation for the application site based on the modeling files submitted by Hyperion.

3.3 AERMAP

For complex terrain situations, AERMOD captures the essential physics of dispersion in complex terrain and therefore needs elevation data that convey the features of the surrounding terrain. In response to this need, AERMAP searches for the terrain height and location that has the greatest influence on dispersion for each individual receptor. This height is the referred to as the hill height scale. Both the base elevation and hill height scale data are produced by AERMAP as a file or files which can be directly inserted into an AERMOD input control file.

The Shuttle Radar Topography Mission (SRTM) 1 Arc Second (~30-meter resolution) International Elevation Dataset based on the UTM Zone 14, WGS84 datum was obtained from http://www.weblakes.com/lakesdem.html. This data set along with AERMAP – the AERMOD Terrain Preprocessor (AERMAP Version 03107) was used to determine terrain elevations for each receptor and receptor hill height values for use with complex terrain. The analysis included all data necessary to cover the entire receptor grid, plus a buffer of 9 km beyond the receptor grid area.

3.4 BPIP

The effects of plume downwash were considered for the applicable point sources within the facility fence line. Direction-specific building dimensions were calculated using the current version of the USEPA-approved Building Profile Input Program (BPIP). Building dimensions for the proposed equipment and existing facility structures were obtained from the BPIP input file (PRIME.pip) submitted by Hyperion to DENR in June 2008. A total of 274 building and/or structures were included in the analysis.

3.5 AERMOD

The AMS/EPA Regulatory Model AERMOD was used to estimate impacts from applicable pollutants. The modeling analysis was conducted using the following options:

- Model Uses NO DRY DEPLETION;
- Model Uses NO WET DEPLETION;

- Model Uses RURAL Dispersion Only;
- Model Uses Regulatory DEFAULT Options:
    - Stack-tip Downwash.
    - Model Accounts for ELEVated Terrain Effects.
    - Use Calms Processing Routine.
    - Use Missing Data Processing Routine.
    - No Exponential Decay; and
- Model Assumes No FLAGPOLE Receptor Heights.

3.6 Ambient Air Boundary and Receptor Grid

Access to the properties is controlled by fencing that is sufficient to prevent unauthorized access and therefore defines the ambient air boundary for modeling purposes.

Cartesian receptor grids were defined using Universal Transverse Mercator (UTM) Zone 14 North American Datum 1983 (NAD83) coordinates. Several receptor grids of varying resolution were defined for the required model analyses. The receptor network consisted of a set of nested grids placed at:

- 50-meter resolution along the ambient air boundary;
- 100-meter resolution extending to 2.5 kilometer from the centroid of the sources;
- 500-meter resolution extending to 5.0 kilometer from the centroid of the sources; and
- 1000-meter resolution extending to 10.0 kilometer from the centroid of the sources.

4.0 National Ambient Air Quality Standards Analysis

As required in 40 CFR §52.21(d), the analysis was conducted to determine if the project would exceed the NAAQS for particulate matter, sulfur dioxide, and nitrogen oxide. The modeled concentration from Hyperion and applicable nearby sources was added to the background concentration to compare to the NAAQS. The sources not included in the model and were in operation prior to the 2006 ambient monitoring conducted by DENR in Sioux Falls, South Dakota are considered to be represented by the monitored background concentration.

Table A-3 displays the comparison of the modeled impacts to the NAAQS and demonstrates that the standards will not be exceeded.

Table A-3 – National Ambient Air Quality Standards Comparison

Pollutant	Modeled Impact[1] (ug/m^3)	Monitored Background[2] (ug/m^3)	Total Impact (ug/m^3)	NAAQS (ug/m^3)	NAAQS Violation
PM10 (24-hour)	25.08	49	74.1	150	No
PM10 (annual)	3.62	19	22.6	50	No
SO_2 (3-hour)	157.1	21	178.1	1,300	No
SO_2 (24-hour)	49.89	5	54.9	365	No
SO_2 (Annual)	5.93	3	8.9	80	No

Pollutant	Modeled Impact[1] (ug/m^3)	Monitored Background[2] (ug/m^3)	Total Impact (ug/m^3)	NAAQS (ug/m^3)	NAAQS Violation
NOx (Annual)	3.38	10	13.4	100	No

[1] – Maximum impacts shown for annual averaging periods. Highest 2nd high values shown for short-term averaging periods; and
[2] – The monitored background is based on the monitoring data collected in Sioux Falls during the calendar year 2006 for the Hilltop monitoring station.

Table A-4 displays the modeled amount of increments consumed compared to the increment standard and demonstrates that the PSD increments will not be exceeded.

Table A-4 – PSD Increment Consumption

Pollutant	Modeled Concentration (ug/m^3) [1]	PSD Class II Increments		Increments Consumed
		Amount (ug/m^3)	Remaining (ug/m^3)	
PM10 (24-hour)	25.07	30 [2]	4.9	No
PM10 (annual)	3.56	17	13.4	No
SO_2 (3-hour)	157.6	512	354.4	No
SO_2 (24-hour)	49.9	91	41.1	No
SO_2 (Annual)	5.88	20	14.1	No
NOx (Annual)	3.27	25	21.7	No

[1] – Maximum impacts shown for annual averaging periods. Highest 2nd high values shown for short-term averaging periods; and
[2] – Can be exceeded once per year.